

APPENDIX A

IBDP INJECTION WELL CCS#1 COMPLETION REPORT

CCS Well#1 Completion Report Certification

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who managed the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Mark Burau, Decatur Corn Plant Manager
Name & Official Title


Signature

217-424-5750
Phone Number

May 5, 2010
Date Signed

Archer Daniels Midland Company

UIC Permit No. UIC-012-ADM
Illinois Environmental Protection Agency
Bureau of Land
Class I – Non-Hazardous Permit

UIC Form 4h, CCS Well #1 Completion Report
Revised May 05, 2010

Geological Sequestration in the Illinois Basin



Location in Application

LOCATION IN APPLICATION.....	2
LIST OF ABBREVIATIONS	3
UIC FORM 4H, CCS WELL #1 COMPLETION REPORT	5
I. TYPE OF PERMIT	6
II. LOCATION, SEE INSTRUCTIONS	6
III. SURFACE ELEVATION	6
IV. WELL DEPTH	7
V. STATIC WATER LEVEL.....	7
VI. DEMONSTRATED FRACTURING PRESSURE	7
VII. INJECTION WELL COMPLETION	7
VIII. WELL SCHEMATIC OR OTHER APPROPRIATE DRAWING OF SURFACE AND SUBSURFACE CONSTRUCTION DETAILS	7
IX. WELL DESIGN AND CONSTRUCTION.....	7
X. TESTS AND LOGS	9
XI. WELL DESIGN AND CONSTRUCTION.....	11
XII. SURFACE FACILITIES	17
XIII. HYDROGEOLOGIC INFORMATION.....	17
XIV. INJECTION FLUID COMPATIBILITY	18
XV. MONITORING PROGRAM	21

Appendices

Appendix VIII. Schematics of injection wellbore, wellhead, and bottom hole completion assembly

Appendix IX. Operational Drilling Log

Appendix X. Records of Tests and Logs During and After Drilling (see file boxes, not in 3-ring binder)

Appendix XI. Casing and Centralizer Tally Sheets

Appendix XIII.

A. Revised UIC Form 4a

B. Revised UIC Form 4d

C. Revised UIC Form 4g

D. Copy of D.N.R. Completion Report Form

NOTE: Appendices have been numbered to correspond to the specific section of the Completion Report Form 4h with which they are associated. Not all sections are accompanied by appendices.

List of Abbreviations

ADM, Archer Daniels Midland
Aka, also known as
Bbls, barrels
BHA, bottom hole assembly
BHCT, bottom hole circulating temperature
BHST, bottom hole static temperature
BOD, basis of design
BOP, blow out preventer
B-T gauge, Bourdon-tube gauge
BTU, British thermal unit
CCS, carbon capture and sequestration
Cf, cubic feet
Cf/sk, cubic feet per sack
CFR, Code of Federal Regulations
Cm, centimeter(s)
CO₂, carbon dioxide
Csg, casing
D&CWOP, Drill and complete well on paper
Eg, for example
EMR, electronic memory recorder
EOR, enhanced oil recovery
Etc, etcetera
F, fahrenheit
FEED, front end engineering design
FOT, fall-off test
Ft., foot or feet
Ft/h, feet per hour
Ft/min, feet per minute
Gal/sk, gallons per sack
GR, gamma ray
HP, high pressure
Hr, hour
ID, inside diameter
IEPA, Illinois Environmental Protection Agency
ISGS, Illinois State Geological Survey
KCl, potassium chloride
L (l), liter(s)
Lb (lbs), pound (pounds)
Lb/ft, pounds per foot
Lb/sk, pounds per sack
M (m), meter(s)
M/h, meters per hour
MASIP, maximum allowable surface injection pressure
MDT, Modular Dynamics Tester* (mark of Schlumberger)
MeV, milli electronvolts

Mg/L, milligrams per liter
MGSC, Midwest Geologic Sequestration Consortium
MI, move in
MO, move out
MVA, monitoring, verification, and accounting
NaCL, sodium chloride
N/A, not applicable
NPDES, National Pollution Discharge Elimination System
NRC, Nuclear Regulatory Commission
OD, outside diameter
P&A, plugging and abandonment
PBTD, Plug back total depth
POOH, pull out of hole
Ppg, pounds per gallon
Psi, pounds per square inch
Psi/ft, pounds per square inch per foot
PV, plastic viscosity
QA, quality assurance
QA Zone, quality assurance zone
QHSE, quality, health, safety, and environment
Qty, quantity
RD, rig down
RU, rig up
RST, Reservoir Saturation Tool* (mark of Schlumberger)
S, seconds
SACROC, Scurry Area Canyon Reef Operators Committee
Sk, sack
SIP, surface injection pressure
SP, spontaneous potential
SRPG, surface-readout pressure gauge
SRTs, step rate tests
Sxs, sacks
TBD, to be determined
Tbg, tubing
TD, total depth
TDS, total dissolved solids
TIH, trip in hole
TOH, trip out of hole
UIC, underground injection control
US DOE, United States Department of Energy
USEPA, United States Environmental Protection Agency
USDW, underground source of drinking water
WFL, water flow log
WOC, wait on cement

UIC Form 4h, CCS Well #1 Completion Report

DRAFT UIC PERMIT FORMS

**ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT APPLICATION**

FORM 4h - WELL COMPLETION REPORT

USEPA ID NUMBER: ILD984791459

IEPA ID NUMBER: 1150155136

WELL NUMBER: CCS #1

I. Type of Permit

Individual: _____

Emergency _____

New _____

Renewal _____

Permit Number _____

Area: Completion Report

Number of well CCS #1

Name of Field _____

Emergency _____

New _____

Renewal _____

Permit Number UIC-012-ADM

Location in Application

II. Location, see instructions

A. Township-Range-Section:

CCS Well #1 is located 438 feet South and 1332 feet East in the Northwest quadrant of Section 5 of Township 16 North and Range 3 East.

B. Latitude/Longitude:

The latitude and longitude coordinates of the well in degrees-minutes-seconds are 39° 52' 36.9402" N and 88° 53' 35.721" W.

C. Closest Municipality

The closest municipality to the well is Decatur, Macon County, IL.

III. Surface Elevation

Surface elevation of the well is 674 feet (205.4 meters) above Mean Sea Level.

IV. Well Depth

The well was drilled to a total measured depth of 7236 feet (2205.5 meters).

V. Static Water Level

The static water level in the well is 430 feet (131 meters) above Mean Sea Level

VI. Demonstrated Fracturing Pressure

The fracture pressure was demonstrated to be 5024 psig at a measured depth of 7025 feet via a step-rate injection test.

VII. Injection Well Completion

The injection well is fully-cased and perforated in the intervals 6982' – 7012' and 7025' – 7050' (wireline reference measured depth in feet) with 6 shots per foot and a shot phasing of 60 degrees.

VIII. Well schematic or other appropriate drawing of surface and subsurface construction details

Please see the injection wellbore, wellhead, and bottom hole completion assembly schematics included in Appendix VIII with this report.

IX. Well Design and Construction

Please see Appendix IX for an operational drilling log based which summarizes the rig performance throughout the drilling of the well.

A. Well hole diameters and corresponding depth intervals

The well was drilled in three stages with the following depth intervals and wellbore diameters:

Surface Hole: 0 – 355 feet, 26-inch diameter

Intermediate Hole: 355 – 5339 feet, 17.5-inch diameter

Final Hole: 5339 – 7236 feet, 12.25-inch diameter

B. Annulus Protection System

For additional details on the Annulus Protection System, please see the Major Permit Modification first submitted on October 30, 2009.

1. *Annular space, ID and OD (inches)*

The annular spaces between the wellbore tubulars are detailed below and reflect the various casing/tubing sizes that were used in the wellbore design.

Surface-Intermediate (0 – 355 feet): 13.375 / 19.124

Intermediate-Final #1 (3630 – 5339 feet): 9.625 / 12.415

Intermediate-Final #2 (0 – 3630 feet): 9.625 / 12.515

Final-Tubing #1 (5285 – 6363 feet): 4.5 / 8.681

Final-Tubing #2 (0 – 5285 feet): 4.5 / 8.835

2. *Type of annular fluid(s)*

The fluids occupying the annular spaces between the wellbore tubulars are described below.

Surface-Intermediate: fully cemented (see cement details in section XI.C)

Intermediate-Final #1 & #2: fully cemented (see cement details in section XI.C)

Final-Tubing #1 & #2: 9.4 lb/gal sodium-chloride brine with corrosion inhibitor and oxygen scavenger additives

3. *Specific gravity of annular fluid*

The fluid occupying the annulus space between the final casing string and the injection tubing has a specific gravity of 1.127. Other annular spaces are filled with solid cement.

4. *Coefficient of annular fluid*

The fluid occupying the annulus space between the final casing string and the injection tubing has a hydrostatic coefficient of 0.488 psi/ft.

5. *Packer(s)*

a. *Setting depth*

The top of the packer is set at a wireline-referenced depth of 6363.7 feet (1939.6 meters) with the center of the sealing elements at 6365 feet (1940 meters).

b. Type

The packer used in the completion assembly is a seal bore, retrievable production packer.

c. Name and model

The packer is a Schlumberger brand Quantum Max Type III Service Tool, Q-Max 13 Chrome designed for 9.625-inch outer diameter casing with linear weights ranging from 47 – 53 lb/ft.

6. Description of fluid spotting frequency, type and quantity

Before installing the lower portion of the injection completion (the packer), the wellbore was filled with approximately 500 barrels of 9.4 lb/gal sodium-chloride brine with corrosion inhibitor and oxygen scavenger additives. This fluid remained in the well as the upper completion (tubing, seal-bore assembly, sensors, etc.) was deployed and latched into the polished bore receptacle of the packer body. This is also the fluid that currently resides in the well and tubing-casing annular space.

7. Information on well driller used for construction of this well

The well was drilled with a rotary-table drilling rig with a water-based circulating mud system. Contact information for the drilling company is listed below.

Les Wilson Inc.
215 Industrial Ave.
Carmi, IL 62821
(618) 382-4666
Contact Person: Bob Wilson

X. Tests and Logs

A variety of wireline logs and tests were conducted during each stage of drilling and completing the well; the types of logs and tests run are listed below with detailed information included in the file box.

A. During Drilling

Intermediate Hole:

- Wireline Logs: (Logs included in File Box)
 - Compensated Neutron Porosity

- Photoelectric Factor & Bulk Density
 - Resistivity
 - Micro-Resistivity Imaging (“fracture finder”)
 - Sonic
 - Elemental Capture Spectroscopy
 - Natural Gamma Ray Spectroscopy
 - Magnetic Resonance
 - Rotary Sidewall Cores
- Drill Stem Test: (Results included in File Box)

Final Hole:

- Wireline Logs: (Logs included in File Box)
 - Compensated Neutron Porosity
 - Photoelectric Factor & Bulk Density
 - Resistivity
 - Micro-Resistivity Imaging (“fracture finder”)
 - Sonic
 - Elemental Capture Spectroscopy
 - Natural Gamma Ray Spectroscopy
 - Magnetic Resonance
 - Rotary Sidewall Cores (Description of test procedures included in File Box Appendix X.A)
 - Formation Pressure Measurements & Fluid Samples
 - ‘Mini’ Fracture Pressure Measurement
 - Zero-offset Vertical Seismic Profile
- Whole Cores: (Description of test procedures included in File Box)
 - Core #1: 5474’ – 5504’
 - Core #2: 6404’ – 6434’
 - Core #3: 6750’ – 6780’

B. During and after casing installation

Surface Hole: (Logs included in File Box)

- Wireline Logs:
 - Variable Density Cement Bond Log

Intermediate Hole: (Logs included in File Box)

- Wireline Logs:
 - Ultrasonic Cement Imaging

Final Hole:

- Wireline Logs: (Logs included in File Box)

- Ultrasonic Cement Imaging
- Variable Density Cement Bond Log
- Pressure/Temperature Log
- Thermal Neutron Decay (Formation Sigma) Log
- Multi-finger Casing Caliper Log
- Casing Collar and Perforating Record Logs
- Injection Full Bore Spinner Logs
- Injectivity Testing: (Results included in File Box)
 - Step-rate Test
 - Pressure Fall-off Tests

C. Demonstrate mechanical integrity prior to operation

A mechanical integrity test of the tubing-casing annular space was conducted and recorded on April 27, 2010. Results are included in the file box.

D. Copies of logs and tests listed above

Please see file boxes accompanying completion report for copies of logs and test results.

E. Description of well stimulation

The injection interval was subjected to a small-scale acid injection delivered in two distinct pumping stages following the addition of perforations. Each acid injection was designed with the primary intention of reducing near-wellbore drilling or 'skin' damage. The chronology of these injections is as follows:

25-Sep-2009: The interval perforated from 7025' to 7050' was acidized with 1,500 gallons of 15% HCl acid and displaced into the formation with 123 barrels of freshwater with a potassium chloride substitute additive.

30-Sep-2009: The intervals perforated from 6,982' to 7,012' and 7025' to 7050' were acidized with 3,000 gallons of 15% HCl acid. The acid was pumped in four 750-gallon stages with 500 gallon spacers of freshwater with a potassium chloride substitute additive between each acid stage. The acid was then displaced into the formation with 121.5 barrels of freshwater with a potassium chloride substitute additive.

XI. Well Design and Construction

The depth intervals, outer and inner diameters, linear weight, grade, coupling type and coupling outer diameters, and thermal conductivity of the various strings of casing and tubing installed in the well are summarized below with appropriate units indicated. Please see Appendix XI for casing tally sheets and locations of casing centralizers.

A. *Casings, see instructions*

1. *Conductive casing*

N/A

2. *Surface casing*

Top Depth (feet): 0

Bottom Depth (feet): 355

O.D. (inch): 20

I.D. (inch): 19.124

Weight (lbs/ft): 94.00

Grade: H-40

Coupling Type: 8-round, STC

Coupling O.D. (inch): 21.00

Thermal Conductivity (BTU/ft-hr-°F): 29.02

3. *Intermediate casing(s)*

Top Section:

Top Depth (feet): 0

Bottom Depth (feet): 3630

O.D. (inch): 13.375

I.D. (inch): 12.515

Weight (lbs/ft): 59.50

Grade: J-55

Coupling Type: Buttress

Coupling O.D. (inch): 14.375

Thermal Conductivity (BTU/ft-hr-°F): 29.02

Bottom Section:

Top Depth (feet): 3630

Bottom Depth (feet): 5339

O.D. (inch): 13.375

I.D. (inch): 12.415

Weight (lbs/ft): 66.17

Grade: J-55

Coupling Type: Buttress

Coupling O.D. (inch): 14.375

Thermal Conductivity (BTU/ft-hr-°F): 29.02

4. *Long string casing*

Top Section:

Top Depth (feet): 0

Bottom Depth (feet): 5272

O.D. (inch): 9.625

I.D. (inch): 8.835
Weight (lbs/ft): 38.97
Grade: N-80
Coupling Type: 8-round, LTC
Coupling O.D. (inch): 10.625
Thermal Conductivity (BTU/ft-hr-°F): 31

Bottom Section:

Top Depth (feet): 5272
Bottom Depth (feet): 7219
O.D. (inch): 9.625
I.D. (inch): 8.681
Weight (lbs/ft): 47.00
Grade: L-80, 13Cr80
Coupling Type: JFE BEAR
Coupling O.D. (inch): 10.485
Thermal Conductivity (BTU/ft-hr-°F): 13

5. *Other casing*

N/A

B. *Injection Tubing, see instructions*

Top Depth (feet): 0
Bottom Depth (feet): 6363
O.D. (inch): 4.5
I.D. (inch): 3.958
Weight (lbs/ft): 12.6
Grade: JFE 13Cr85
Coupling Type: JFE BEAR
Coupling O.D. (inch): 5.00
Thermal Conductivity (BTU/ft-hr-°F): 13

1. *Maximum allowable suspended weight based on joint strength*

The joint strength of the tubing and, hence, maximum allowable suspended weight is 306 Kip (1361 kN).

2. *Weight of injection tubing string (axial load) in air*

The injection tubing weighs (in air) 79539 lbs (36078 kgs).

C. *Cement, see instructions*

Details about the various cement blends used in each stage of the construction of CCS Well #1, including the depth interval, type and grade, additives, quantity, thermal conductivity, and whether or not the cement was circulated to surface, are summarized in the following sections with

the appropriate units indicated.

1. *Conductive casing*

N/A

2. *Surface casing(s)*

Depth Interval (feet): 0 – 355

Type/Grade (Lead): Class A

Additives (Lead): 0.2% D-46 Anti-foam, 0.25 lb/sk flake

Quantity (Lead) (cubic yards): 58

Type/Grade (Tail): Class A

Additives (Tail): 1% CaCl₂, 0.2% D-46 Anti-foam, 0.25 lb/sk flake

Quantity (Tail) (cubic yards): 38.67

Circulated: Yes

Thermal Conductivity (BTU/ft-hr-°F): 0.7

3. *Intermediate casing*

A comment on the intermediate casing cement design:

The lead cement system was changed from that proposed in the permit application due to lost circulation encountered while drilling the well. Lost circulation was encountered in the Knox at a depth of approximately 4562 feet and again in the Ironton-Galesville at 5017 feet. Both zones were sealed off with cement plugs, however, there was concern that during cementing operations the plugs might fail and lost circulation would be encountered while cementing. Therefore, the cement job was completed in two stages with a stage collar run at 3715 feet. The first stage cement was changed from a Class A system to Class H cement due to better performance characteristics of Class H cement – primarily lack of a gelation tendency present in Class A. The second stage lead system was changed from a 50/50 Class A- Pozzolan with 6% bentonite and 10% salt mixed at a density of 13.3 ppg to a 65/35 Class A- Pozzolan system with 4% bentonite and 10% salt with 5 lbs/sk Kolite mixed at a density of 12.7 ppg in order to lighten the slurry, thus enabling cement to be circulated to surface. The difference in 24 hour compressive strength was small: 575 psi in 24 hours for the 65/35 system compared to 655 psi in 24 hours for the original 50/50 system. The actual job went very well with cement circulated to surface and good bonding obtained from the base of the intermediate casing to surface.

Stage 1:

Depth Interval (feet): 3715 – 5339

Type/Grade (Lead): Class H

Additives (Lead):

Additives		
Code	Concentration	Function
D081	0.040 gal/sk blend	Retarder
D047	0.020 gal/sk blend	Antifoam

Quantity (Lead) (cubic yards): 54.7

Circulated: Yes

Thermal Conductivity (BTU/ft-hr-°F): 0.71

Type/Grade (Slurry): Class H

Additives (Slurry):

Additives		
Code	Concentration	Function
D081	0.080 gal/sk blend	Retarder
D047	0.020 gal/sk blend	Antifoam

Quantity (Slurry) (cubic yards): 46.3

Circulated: No

Thermal Conductivity (BTU/ft-hr-°F): 0.75

Type/Grade (Tail): Class H

Additives (Tail):

Additives		
Code	Concentration	Function
D081	0.080 gal/sk blend	Retarder
D047	0.020 gal/sk blend	Antifoam

Quantity (Tail) (cubic yards): 45.8

Circulated: No

Thermal Conductivity (BTU/ft-hr-°F): 0.78

Stage 2:

Depth Interval (feet): 0 – 3715

Type/Grade (Lead): 35:65 (pozzolan:cement blend)

Additives (Lead):

Additives		
Code	Concentration	Function
D020	4.000 %BWOB	Extender
D044	10.000 %BWOW	Salt
D065	0.600 %BWOB	Dispersant
D167	0.200 %BWOB	Fluid loss
D046	0.200 %BWOB	Antifoam
D042	4.787 lb/sk blend	LCM/extender

Quantity (Lead) (cubic yards): 221.3

Circulated: Yes

Thermal Conductivity (BTU/ft-hr-°F): 0.47

Type/Grade (Slurry): 35:65 (pozzolan:cement blend)
Additives (Slurry):

Additives		
Code	Concentration	Function
D020	4.000 %BWOB	Extender
D044	10.000 %BWOW	Salt
D065	0.600 %BWOB	Dispersant
D167	0.200 %BWOB	Fluid loss
D046	0.200 %BWOB	Antifoam
D042	4.787 lb/sk blend	LCM/extender

Quantity (Slurry) (cubic yards): 239.2
Circulated: No
Thermal Conductivity (BTU/ft-hr-°F): 0.5

Type/Grade (Tail): Class H
Additives (Tail):

Additives		
Code	Concentration	Function
D047	0.020 gal/sk blend	Antifoam
D081	0.020 gal/sk blend	Retarder

Quantity (Tail) (cubic yards): 38.67
Circulated: No
Thermal Conductivity (BTU/ft-hr-°F): 0.72

4. *Long string casing*

Depth Interval (feet): 0 – 4170
Type/Grade (Lead): 35:65 LP3:A (pozzolan:cement blend)
Additives (Lead):

Additives		
Code	Concentration	Function
D020	6.000 %BWOB	Extender
D046	0.200 %BWOB	Antifoam
D167	0.400 %BWOB	Fluid loss

Quantity (Lead) (cubic yards): 249.5
Circulated: Yes
Thermal Conductivity (BTU/ft-hr-°F): 0.47

Depth Interval (feet): 4170 - 7219
Type/Grade (Tail): EverCRETE
Additives (Tail):

Additives		
Code	Concentration	Function
D081	0.035 gal/sk blend	Retarder
D168	0.170 gal/sk blend	Fluid loss
D206	0.030 gal/sk blend	Antifoam
D080	0.050 gal/sk blend	Dispersant

Quantity (Tail) (cubic yards): 112.1

Circulated: No

Thermal Conductivity (BTU/ft-hr-°F): 0.72

5. *Other casing*

N/A

XII. Surface Facilities

For additional details on the surface facilities, please see the Major Permit Modification first submitted on October 30, 2009.

A. *Filters(s)*

N/A

B. *Injection pump(s)*

The table below summarizes the specifications of the various injection pumps in the surface compression system. Please see annotations on the Process Control Strategy Diagram accompanying the Major Permit Modification first submitted on October 30, 2009 for the location of pumps with respect to the entire compression/dehydration facility.

TYPE	NAME	MODEL NUMBER	CAPACITY
Multistage Centrifugal Blower	BL-101	HSI 18604	21 MMSCFD
Reciprocating Compressor	VC-201 & VC-301	Ariel JGC6-4, 3250 HP	10.85 MMSCFD (each)
Multistage Centrifugal Pump	ESP PUMP	Wood Group SJ0270	21 MMSCFD (282.9 US GPM)

XIII. Hydrogeologic Information

A. *Revised UIC Form 4a*

Please see Revised UIC Form 4a included as Appendix XIII.A.

B. *Revised UIC Form 4d using actual data on injection formation*

Please see Revised UIC Form 4d included as Appendix XIII.B.

C. *Revised UIC Form 4g*

Please see Revised UIC Form 4g included as Appendix XIII.C.

D. Copy of well completion report submitted to the Department of Natural Resources (Formerly Mines and Minerals)

Please see attached copy of well completion report submitted to the DNR included as Appendix XIII.D.

E. Copy of any plugging affidavits on injection well filed with Department of Natural Resources

N/A

XIV. Injection Fluid Compatibility

The following information is presented as an update to that which was previously submitted with the original permit application in Chapter 9: UIC Form 4f, Section V. In the cases where no new information is presented, reference is made to the language in the original permit application.

A. Compatibility with injection zones fluid

No compatibility problems are anticipated in the injection zone. Geochemical modeling was used to predict the effects of injecting supercritical CO₂ into a model Mt. Simon sandstone (Berger et al., 2009). Based on chemical and mineralogical data from the Manlove Gas Storage Field in Illinois, the geochemical modeling software package, Geochemist's Workbench (Bethke, 2006), was used to simulate geochemical reactions. As expected, the injected CO₂ decreased the pH of the formation brine to about pH 4.5. As the reaction was allowed to progress, the pH of the formation brine increased to pH 5.4.

B. Compatibility with minerals in the injection zone

In the geochemical simulations mentioned in above, Berger et al. (2009), it was predicted that illite and glauconite dissolved initially. As the reaction was allowed to proceed, kaolinite and smectite were predicted to precipitate. It was predicted that the volume of pore space would not be significantly altered (Berger et al., 2009). Therefore, no compatibility problems, such as a major reduction in injection-formation permeability resulting from chemical precipitates, are expected.

C. Compatibility with minerals in confining zone

In the geochemical simulations mentioned above, Geochemist's Workbench predicted that as the CO₂ reacts with the Eau Claire formation, illite and smectite would initially dissolve, but that the dissolved CO₂ could be precipitated as carbonates (Berger et al., 2009). This dissolution and precipitation process is not expected to affect the caprock integrity.

D. *Compatibility with injection well components*

1. *Injection tubing*

As the CO₂ will be dehydrated to less than 30 lb/MMSCF or 630 ppmv, the expected reactivity with the tubing will be negligible. Nevertheless, the injection tubing is composed of chrome steel (13 Cr) and is specifically engineered to function in environments with high concentrations of CO₂. This reflects the design specifications approved under the UIC Permit No. UIC-012-ADM.

2. *Long string casing*

As per the design specifications approved under the UIC Permit No. UIC-012-ADM, the long string casing installed from total depth of the well past the base of the confining layer (to a depth of 5285') is composed of chrome steel (13 CR) and is specifically engineered to function in environments with high concentrations of CO₂. The long string casing in the remainder of the well (5285' to surface) is carbon steel. This section of casing, however, will remain isolated from the injected CO₂ due to the tubing-annulus protection system and the protective cement sheath in which it is encased. Reactivity between the injected CO₂ and the long string casing is expected to be negligible.

3. *Cement*

As specified under UIC Permit No. UIC-012-ADM, the long string casing is encased from total depth to approximately 4170 feet (or approximately 1170 feet into the intermediate casing string) in Schlumberger's proprietary blend of CO₂-resistant cement, EverCRETE. Technical descriptions of the cement properties can be found in the original permit application (Chapter 9: UIC Form 4f, Section V, pages 135-139) and accompanying appendices. Reactivity between the injected CO₂ and the cement is expected to be negligible.

4. *Annular fluid*

The annular fluid between the injection tubing and the long string casing is a 9.4 lb/gal sodium chloride brine with corrosion inhibitor and oxygen scavenger additives that are compatible with the injected CO₂ and will minimize corrosion to the tubing and casing. Reactivity between the injected CO₂ and the annular fluid is expected to be negligible.

5. *Packer(s)*

The injection packer installed is a Schlumberger Quantum Max Type III Seal-bore Assembly packer composed of chrome steel (13 Cr). The sealing elements of the packer and seal-bore assembly are comprised of Nitrile rubber which is designed to be durable in environments with high CO₂ concentration. As a result, reactivity between the injected CO₂ and the injection packer is expected to be negligible.

6. *Well head equipment*

Components of the wellhead equipment expected to be in contact with the injected CO₂ are constructed from schedule 310 and 410 stainless steel; therefore, no adverse reactions are expected between the injected CO₂ and any the wellhead components.

7. *Holding tank(s) and flow lines*

There will be no holding tanks for the injection fluid. Consequently, there are no CO₂ holding tank compatibility concerns.

The CO₂ is transferred from the surface compression facilities via approximately 6400 feet of 6-inch Schedule 40 carbon steel pipeline to the wellhead. The design basis for the surface facility gas dehydration unit is to reduce the water content of the CO₂ to a range of 7 to 30 lb of H₂O/MMSCF (150 to 630 ppmv H₂O). This water content range is consistent with typical U.S. CO₂ transmission pipeline water content specifications for carbon steel pipe, therefore, no corrosive reactions are anticipated.

E. *Full description of compatibility of injection fluid with items A-D*

In summary, there are no compatibility concerns with the injection zone, minerals in the injection zone, and minerals in the confining zone. The CO₂ is expected to have negligible to no reaction with the minerals and formation water. Any reactions that may occur are not expected to affect the containment of the CO₂ below the primary seal.

Components to the injection wellhead and wellbore have been selected to minimize and negate any reaction with the CO₂. Additional details on the corrosion monitoring plan are included the Major Permit Modification first submitted on October 30, 2009.

Sources:

Bethke, C.M.. 2006. The Geochemist's Workbench (Release 6.0) Reference Manual. RockWare, Inc., Golden CO, 240 p.

Berger, P.M., Mehnert, E., and Roy, W.R. (2009) Geochemical Modeling of Carbon Sequestration in the Mt. Simon Sandstone. Geological Society of America *Abstracts with Programs*, vol. 41, no. 4, p. 4.

XV. *Monitoring Program*

Details of the various process monitoring sensors and gauges are summarized below and include the location of the device, the brand and model number, the device type (electrical or mechanical), and whether or not the device is continuously recording.

A. *Injection pressure gauge(s)*

Surface Injection Pressure Gauge: PIT-009 (Please see Process Control Strategy Diagram in Appendix XII)

Location: Installed directly into the wellhead tree cap port.

Make / Model: ABB / 264HSVKTA1L1N2

Type: Electrical; Continuous Recording

Operating Range (psig): 0 – 4000; this exceeds maximum operating range of system by more than 20%

Downhole Injection Pressure Gauge: (Please see injection wellbore schematic in Appendix VIII)

Location: Mounted within the downhole solid gauge mandrel at a measured depth of 6325 feet as part of the tubing completion.

Make / Model: Schlumberger / NDPG-CA (P/N 500897)

Type: Electrical; Continuous Recording

Operating Range (psig): 0 – 10000; this exceeds maximum operating range of system by more than 20%

B. *Casing-tubing annular pressure gauge(s)*

For additional details on the Annulus Protection System, refer to the description included as Appendix IX.A.

Location: Mounted on the wellhead port open to the casing-tubing annulus.

Make / Model: Unknown at this time; compliant with ASME B 40.1 specifications

Type: Electrical (4-20 mA); Continuous Recording

Operating Range (psig): 0 – 600; this exceeds maximum operating range of system by more than 20%

C. *Flow meter(s)*

Location: Installed downstream of the multistage centrifugal pump (FIT006 – Please see Process Control Strategy Diagram in Appendix XII)

Make / Model: SCADASense / 4203

Type: Electrical; Continuous Recording

Operating Range (tonnes/day): 250 – 1100; this meets the maximum operating range of the system but does not exceed it by more than 20%

D. pH recording device(s)

N/A

E. Temperature

Surface Temperature Gauge: TIT-009 (Please see Process Control Strategy Diagram in Appendix XII)

Location: Installed downstream of the multistage centrifugal pump along the section of pipeline immediately upstream of the wellhead wing valve inlet and check valve.

Make / Model: INOR / Meso-HX 70MEHX1001

Type: Electrical; Continuous Recording

Operating Range (degF): -40 – 185; this exceeds maximum operating range of system by more than 20%

Downhole Temperature Gauge: (Please see injection wellbore schematic in Appendix VIII)

Location: Mounted within the downhole solid gauge mandrel at a measured depth of 6325 feet as part of the tubing completion.

Make / Model: Schlumberger / NDPG-CA (P/N 500897)

Type: Electrical; Continuous Recording

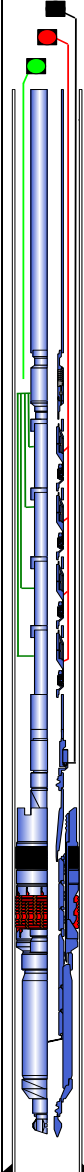
Operating Range (degF): 0 – 212; this exceeds maximum operating range of system by more than 20%

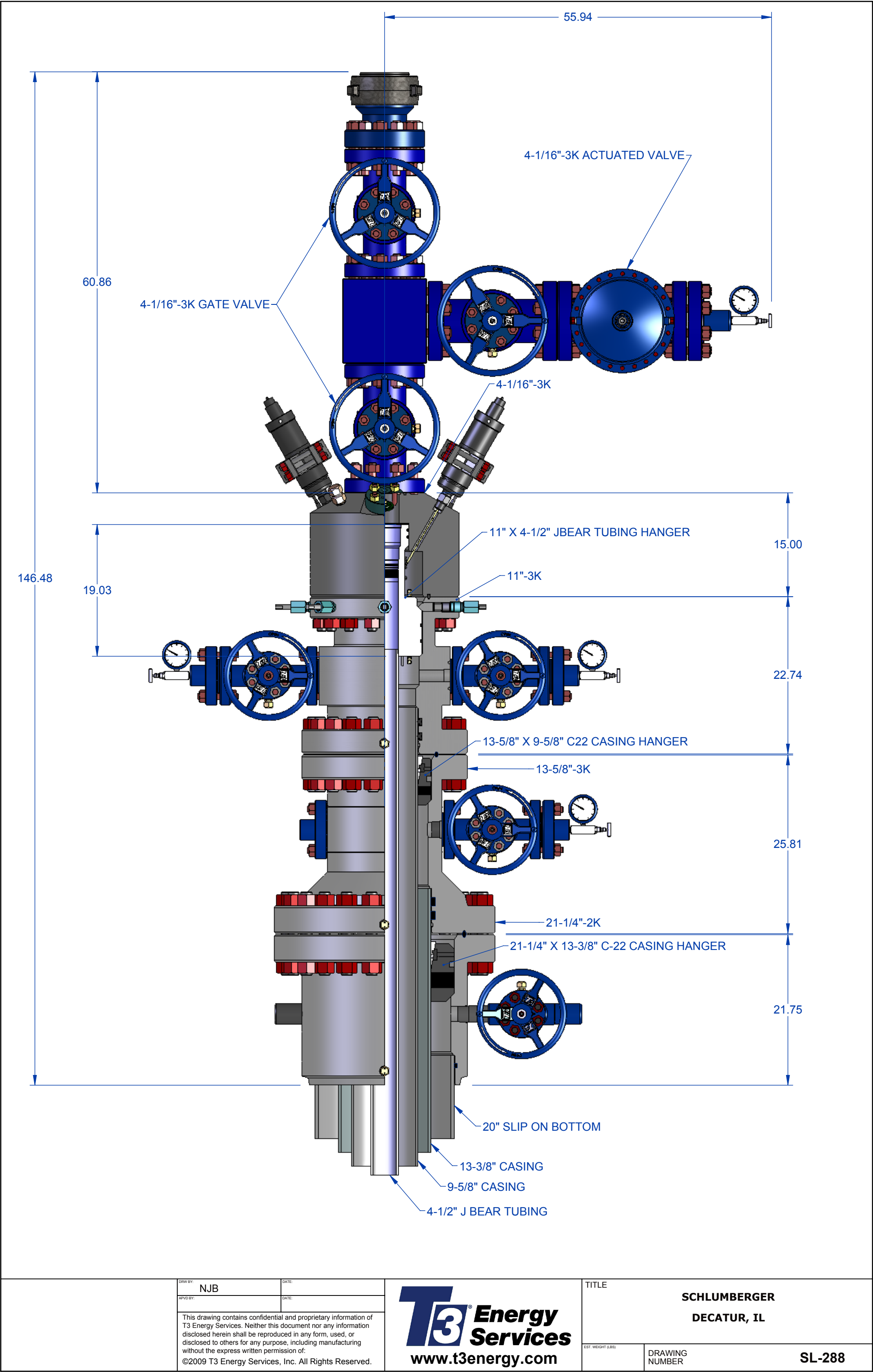
Appendix VIII – CCS Well #1 Wellbore & Wellhead Schematics



Illinois Basin - Decatur Project

Prepared for: Paul Huges		Date: Nov-24-2009		Casing: 9 5/8" 40&47# N-80& CR13		Completion Type: Upper Completion		Pressure/Temp.		
Field Name: Illinois Basin		Well Name: ADM CCS #1		Casing Drift ID 8.681/Drift 8.525		Rig: Wilson 28		3245psi BHP 135 Degree F		
Prepared by: Roberto Schuldes		District/Phone #: Houma, LA / (985) 851-1074								
Production Tubing: 4 1/2" 12.6# CR13 JFE Bear										
String Weight Include Block -						Rig: Ideco H-35/Pioner Rig 15				
Block Weight -						Item's Actual Pipe Measured Length - 6335.32				
Weight On Locator -						Packer Fluid Type and Weight - 9.4 ppg NaCl				
Original RKB -						Completion Fluid Type and Weight - 9.4 ppg NaCl				
				All Depths Are Wireline Depths						
				Production String Assembly						
0.00	0.55	11.000	3.958	Hanger PN: HTG6561, Top Thread: 4-1/2 EUE 8rd						
0.55	30.75	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joints (5.52+10.34+8.34+6.55)						
31.30	4883.83	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear tubing (Adjusted by 49.07)						
4915.13	10.34	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint						
4925.47	9.97	8.350	3.958	Geophone #3						
4935.44	10.34	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint						
4945.78	786.51	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear tubing						
5732.29	10.36	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint						
5742.65	9.97	8.350	3.958	Geophone #2						
5752.62	10.38	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint						
5763.00	236.64	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear tubing						
5999.64	8.34	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint						
6007.98	118.40	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear tubing						
6126.38	10.34	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint						
6136.72	9.97	8.350	3.958	Geophone #1						
6146.69	10.34	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint						
6157.03	157.96	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear tubing						
6314.99	10.36	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint						
6325.35	6.01	5.712	3.879	4 1/2, 12.60, SGM-FS, NDPG/NLOG, SINGLE, TUBING						
6331.36	10.33	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint						
6341.69	10.33	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint						
6352.02	1.36	4.500	3.813	4 1/2" x 3.813 X-nipple JFE Bear						
6353.38	10.33	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint						
6363.71	2.08	7.000	3.500	4.75" Snap latch 13Cr (4 1/2 12.6# JFE Bear)						
6365.79	9.00	4.690	3.500	4.75" Seal Unit 4.124" 13Cr SLHT pin x box ID:127088 PN:4						
6374.79	0.81	4.690	3.500	X-O, 4.063-8 SA Pin x 4.124" 13Cr SLHT Box PN: 100714412						
6375.60	2.51	4.724	3.750	SAGS w/ inner sleeve 13chr 4.063 8SA Box ID: 164949-01, PN:100602582/AA						
6378.11				End of Assembly						
				Quantum Max Packer Assembly						
Depth	Length	ID	OD							
6363.71	6.47	4.750	8.341	9 5/8" x 4.75" (47-53.5#) Q-Max 13Cr w/HNBR ID# 250148-03						
6370.18	0.83	5.443	7.013	X-O, 6.375" 6-SA Box x 6.25" 8-SA Box HOS-252940						
6371.01	19.06	4.750	6.974	9 5/8" x 4.75" x 20" PBR PO# 101046						
6390.07	1.14	3.431	6.950	X-O, 4" 11.6# NU 8rd Pin x 6.375" 6-SA Box HOS-252941						
6391.21	10.33	3.442	4.752	4" NU 8rd 11.6# 13Cr85 Pup Joint w/ Collar						
6401.54	1.54	3.313	4.744	4" x 3.313" X-Nipple C-36025-01						
6403.08	10.31	3.442	4.745	4" NU 8rd 11.6# 13Cr85 Pup Joint w/ Collar						
6413.39	0.71	3.672	4.780	4" NU 8rd 11.6# 13Cr85 Wireline Re-Entry Guide w/ mule shoe SO# 729775						
6414.10				EOA						





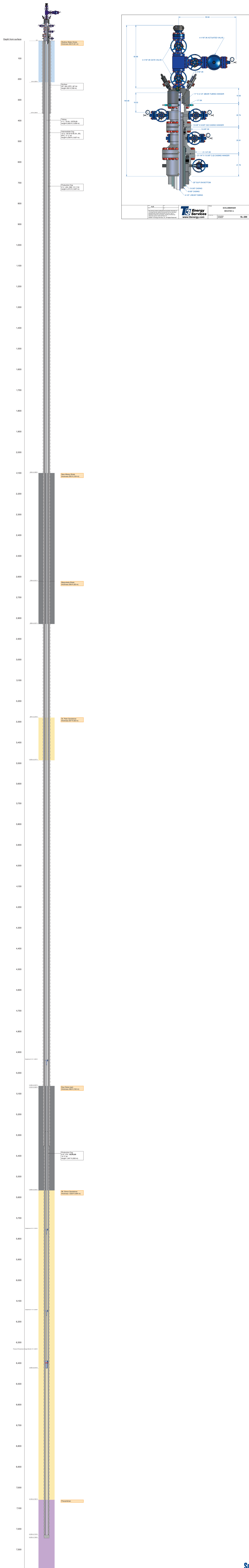
DRW BY: NJB	DATE:
APVD BY:	DATE:
This drawing contains confidential and proprietary information of T3 Energy Services. Neither this document nor any information disclosed herein shall be reproduced in any form, used, or disclosed to others for any purpose, including manufacturing without the express written permission of: ©2009 T3 Energy Services, Inc. All Rights Reserved.	



T3 Energy Services
www.t3energy.com

TITLE SCHLUMBERGER DECATUR, IL	
EST. WEIGHT (LBS)	DRAWING NUMBER SL-288

Appendix VIII - CCS# 1 Injection Wellbore Schematic



Appendix IX – CCS Well #1 Operational Drilling Log

NOTE: the following operational drilling log is a continuous record of key drilling rig performance metrics which can be used to make qualitative inferences about the various geologic properties and drilling conditions encountered in the well. The log, which includes the entirety of the drilling operation of CCS Well #1, includes such information as the weight on the drilling bit, the weight on the rig's travelling block ('Hook Load'), rate of rotation, rotational torque, mud pump output, rate of penetration, along with the driller's comments during various operational milestones or decision points and the chronology of these events.

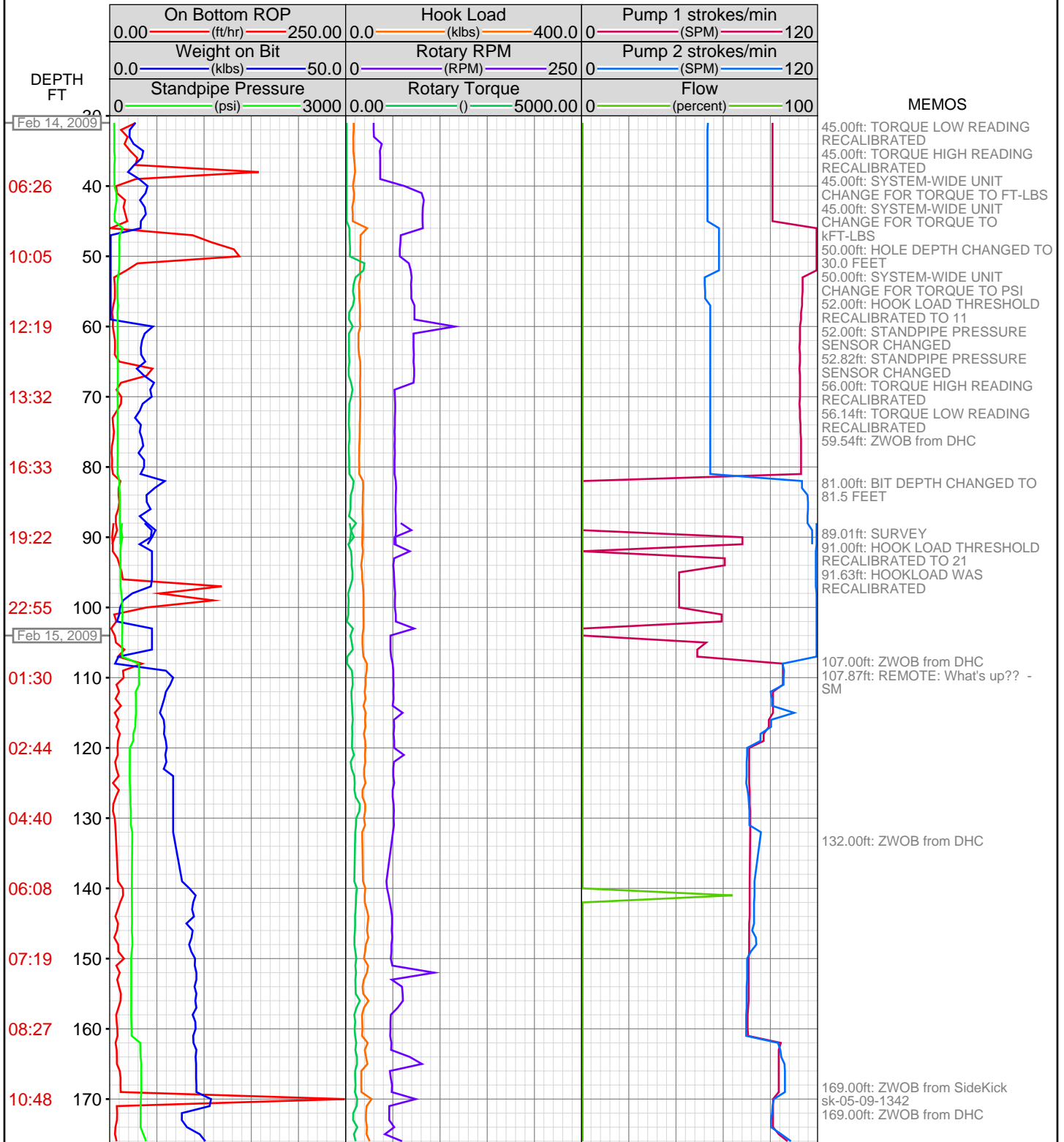
NOTE: the following operational drilling log is a continuous record of key drilling rig performance metrics which can be used to make qualitative inferences about the various geologic properties and drilling conditions encountered in the well. The log, which includes the entirety of the drilling operation of CCS Well #1, includes such information as the weight on the drilling bit, the weight on the rig's travelling block ('Hook Load'), rate of rotation, rotational torque, mud pump output, rate of penetration, along with the driller's comments during various operational milestones or decision points and the chronology of these events.

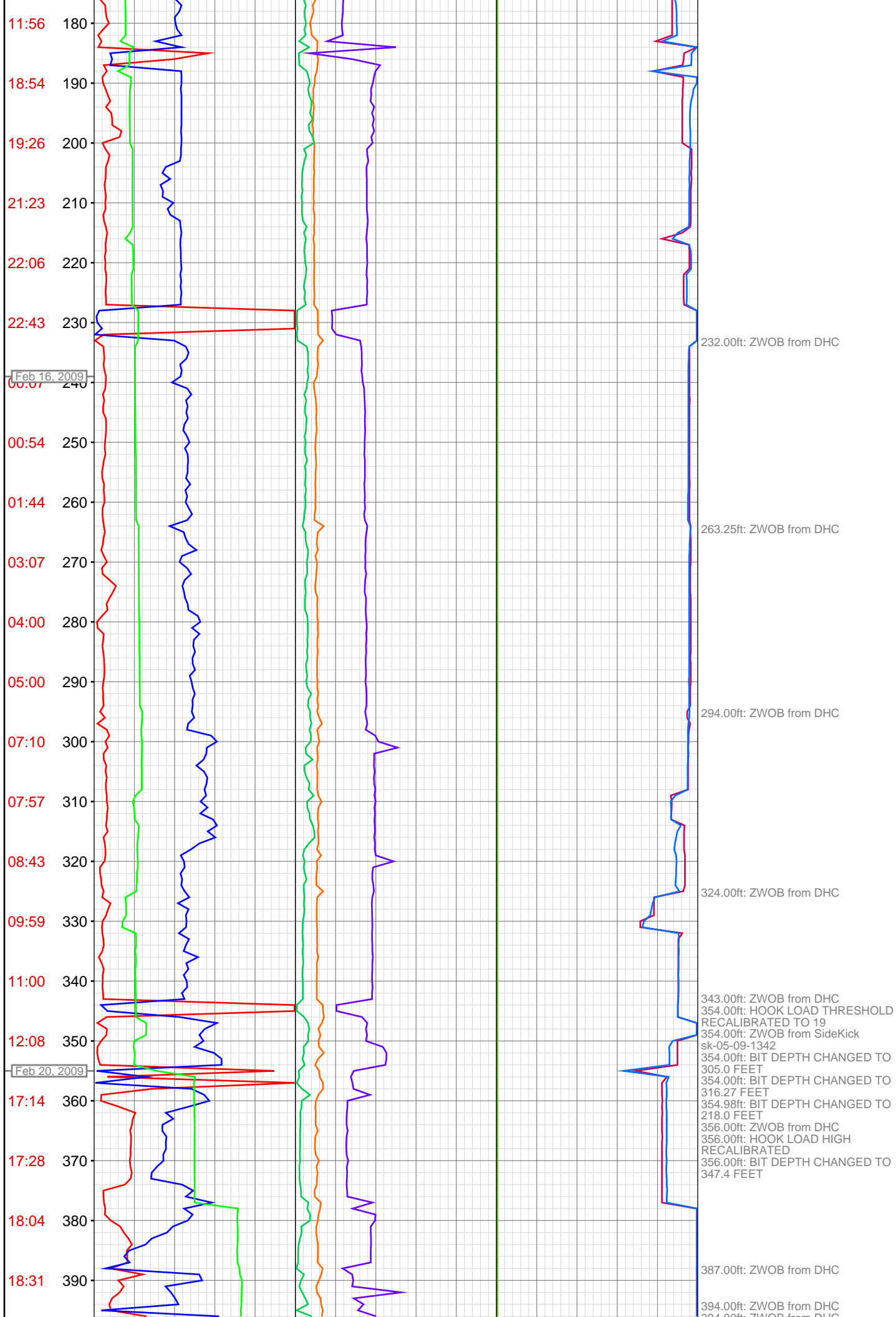
DataHub EDR Log

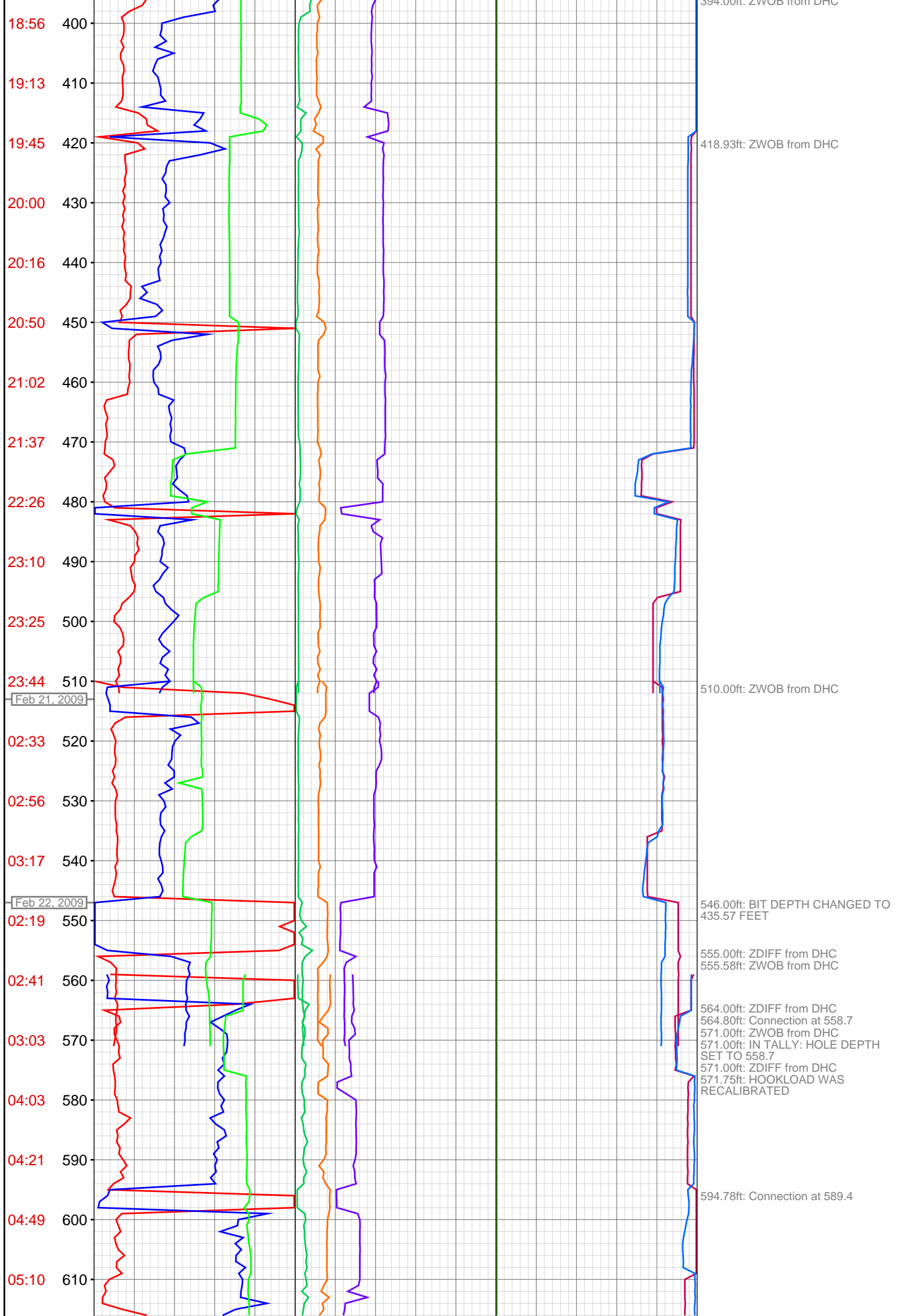
Tue Mar 16, 2010 08:33:19
Well Dossier 1607061
Ethan Chabora

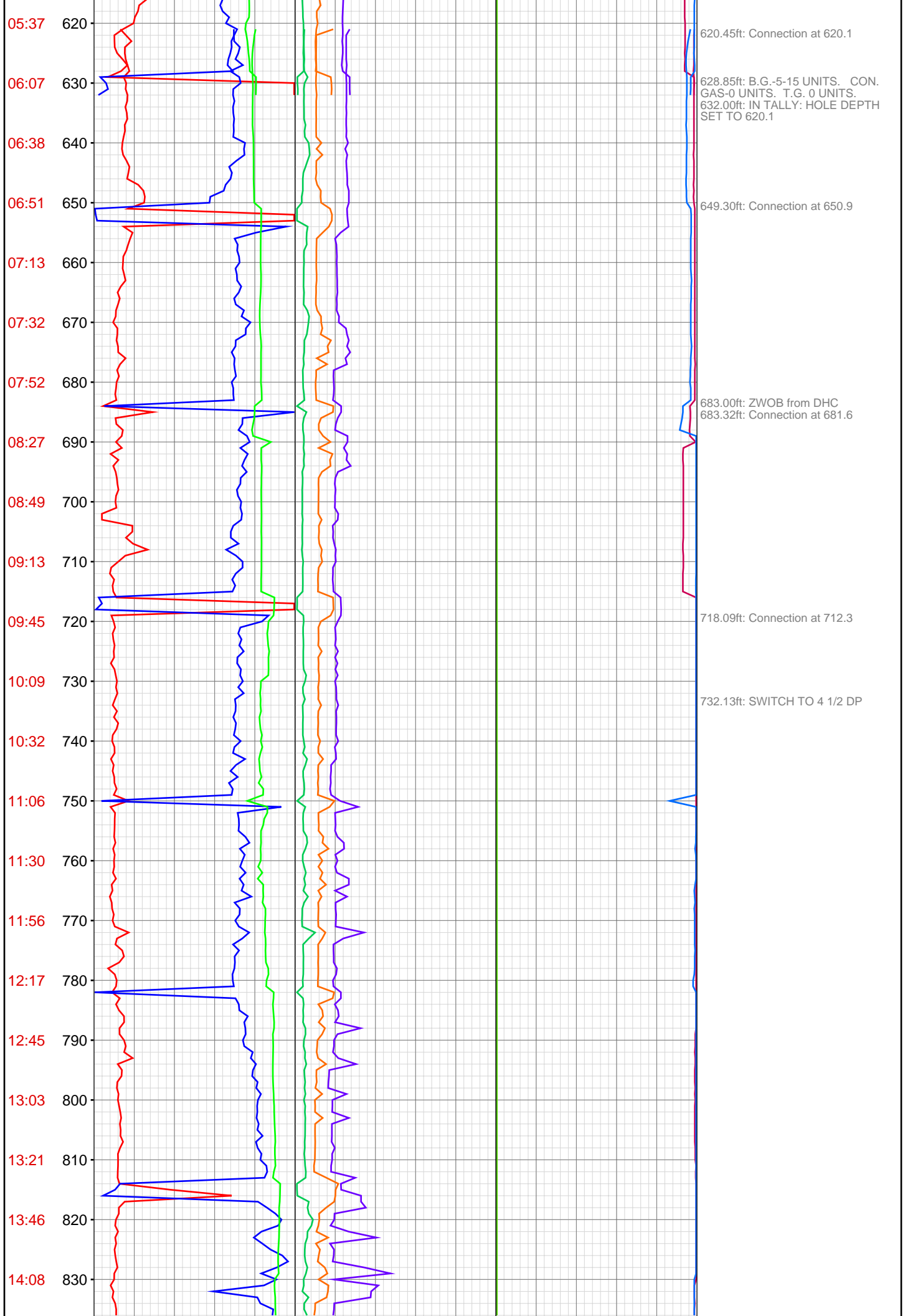
OPERATOR: ADM (Archer Daniel Midland)
WELL: ADM COMPANY CCS WELL NO 1
FIELD:
LOCATION:
COUNTRY: USA
RIG: Les-Wilson 25

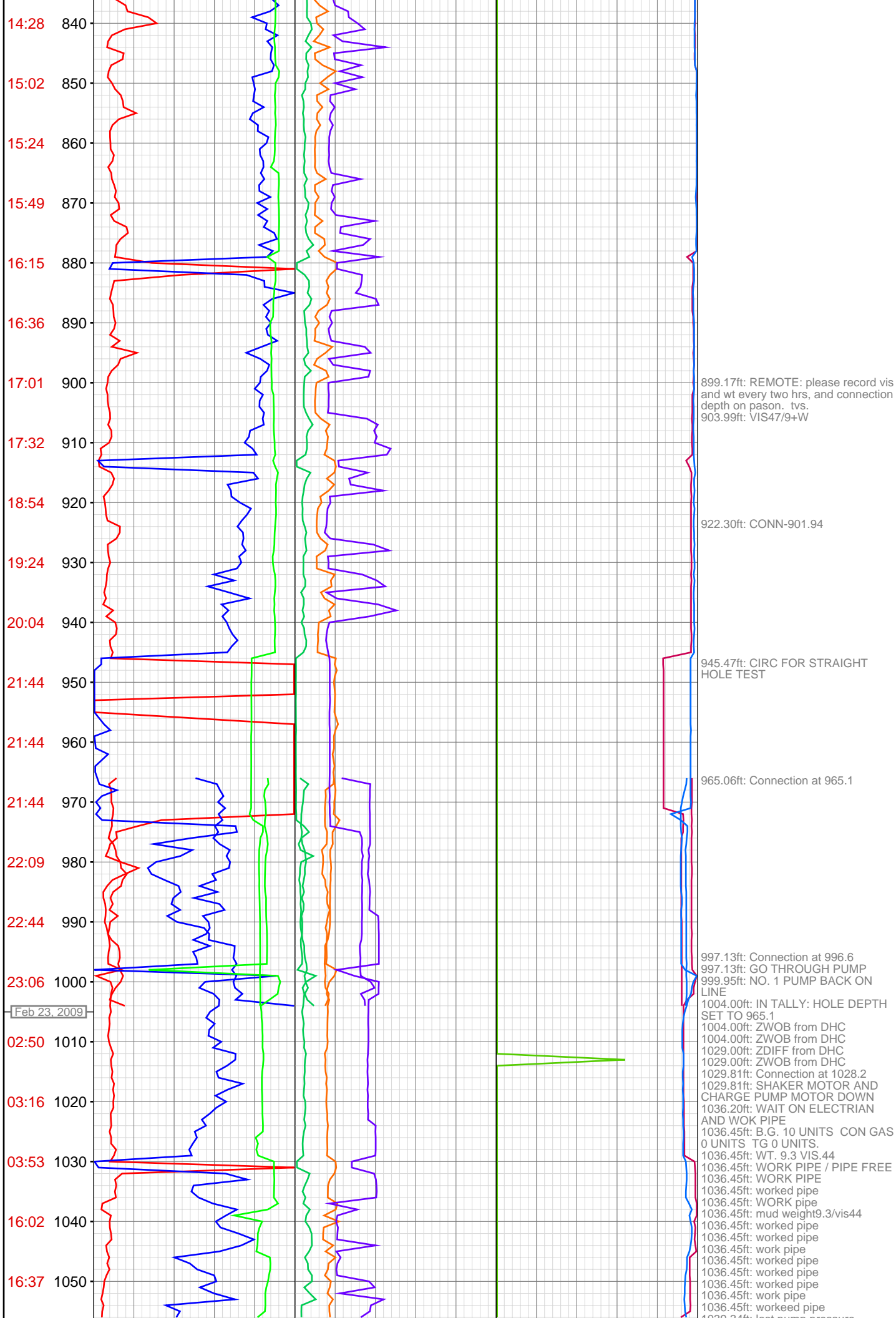
CONTRACTOR: Les Wilson Drilling
UNIQUE WELL ID:
SPUD DATE: Feb 14, 2009 05:00
RELEASE DATE: May 05, 2009 10:08

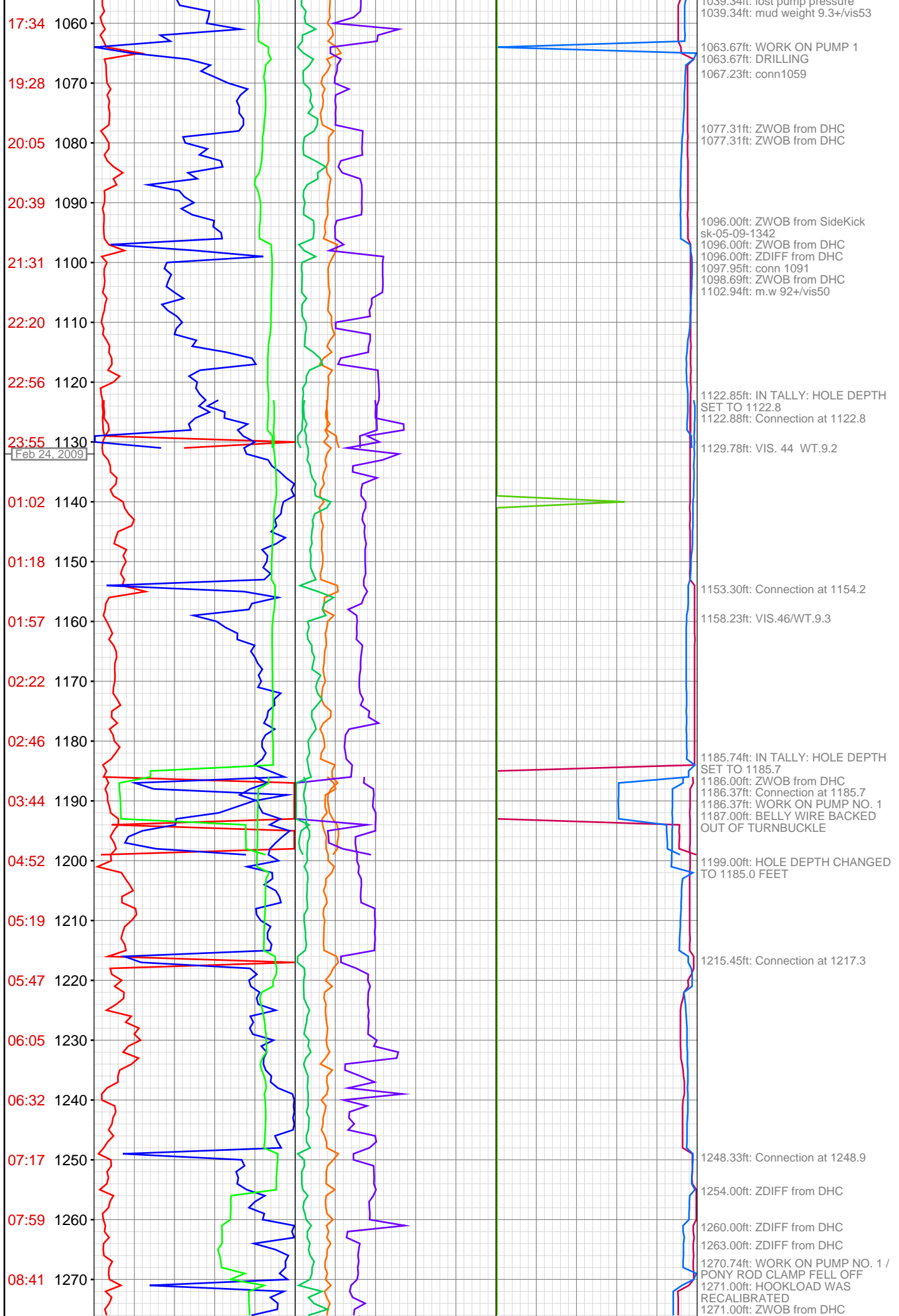


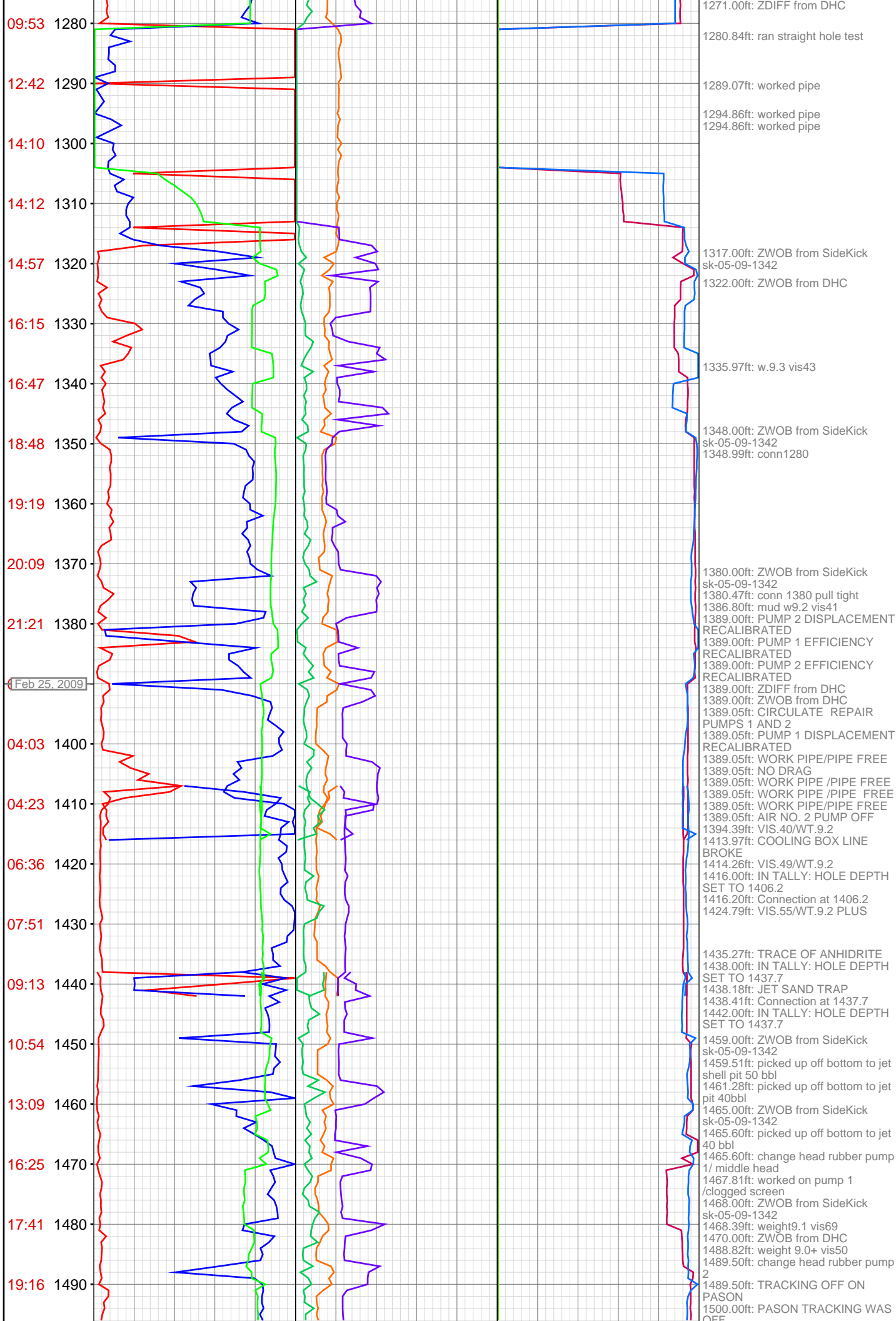


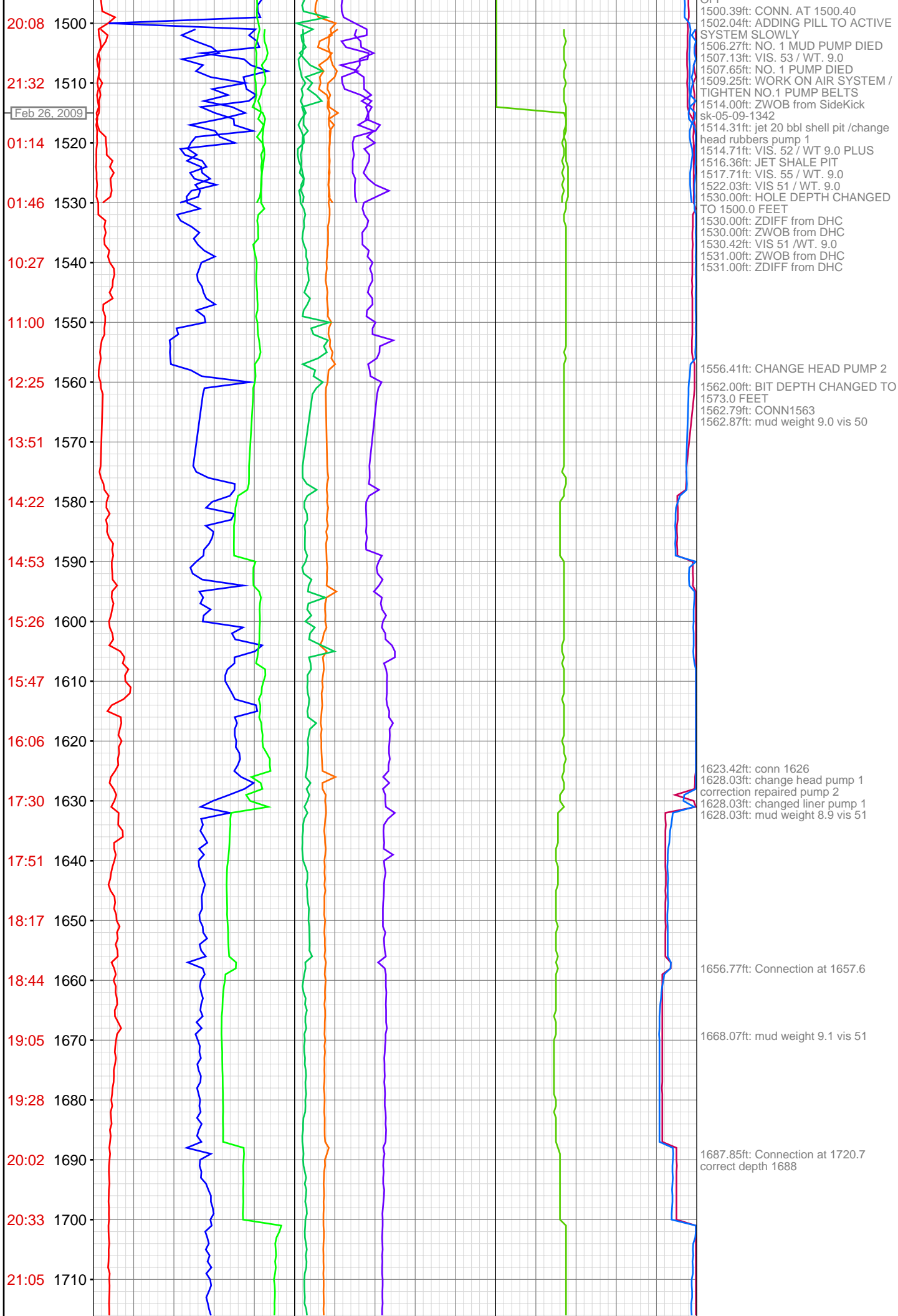


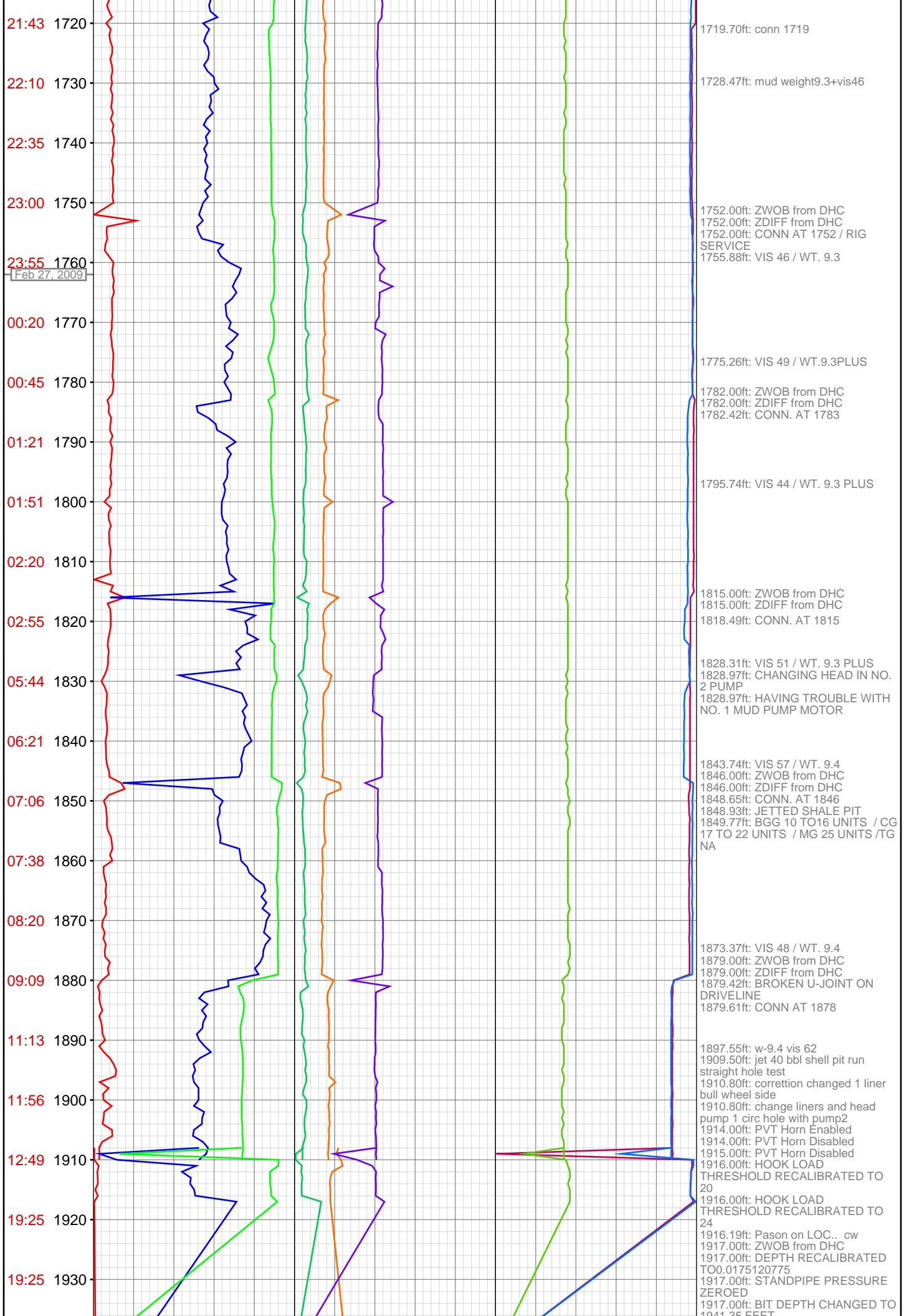


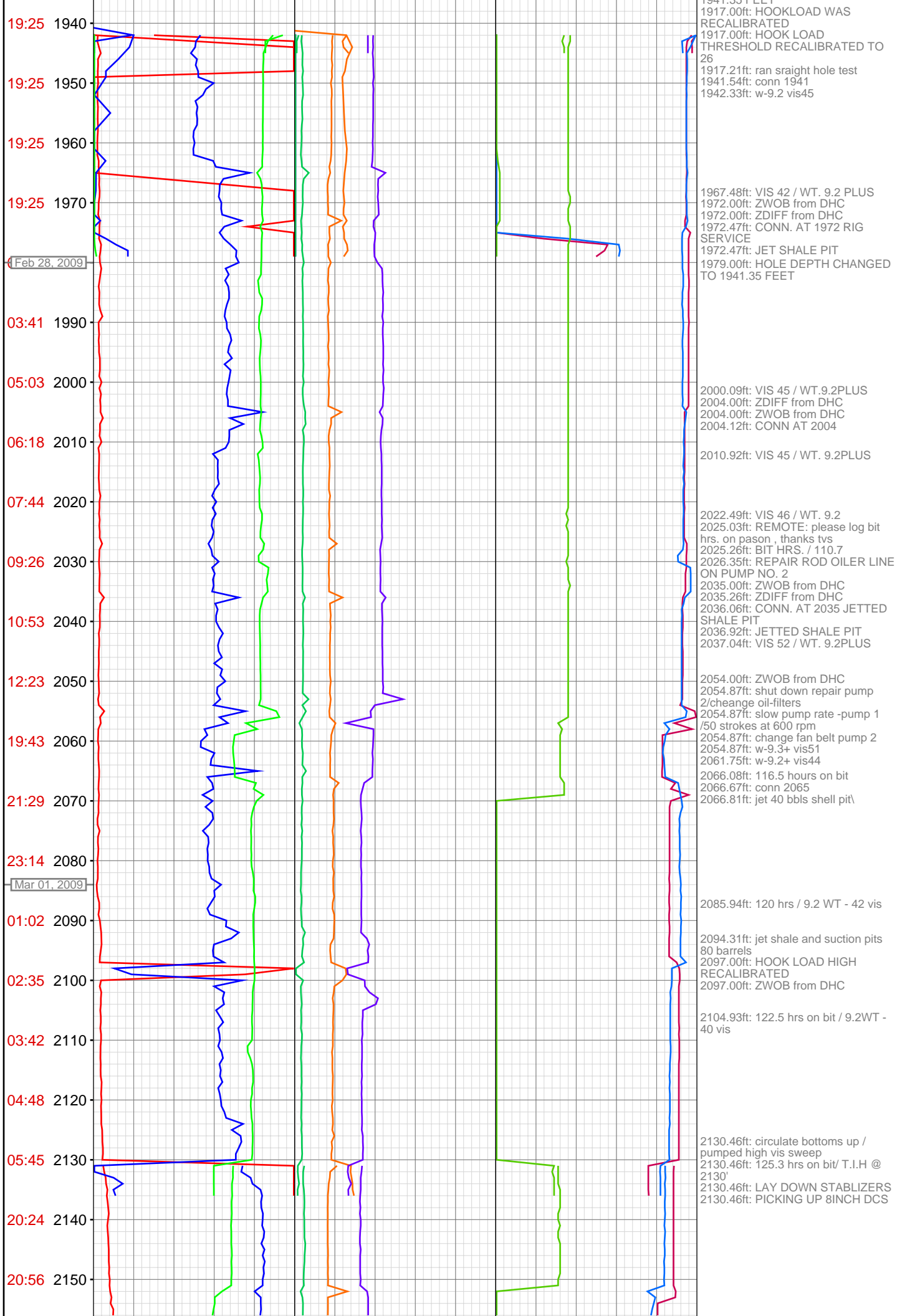


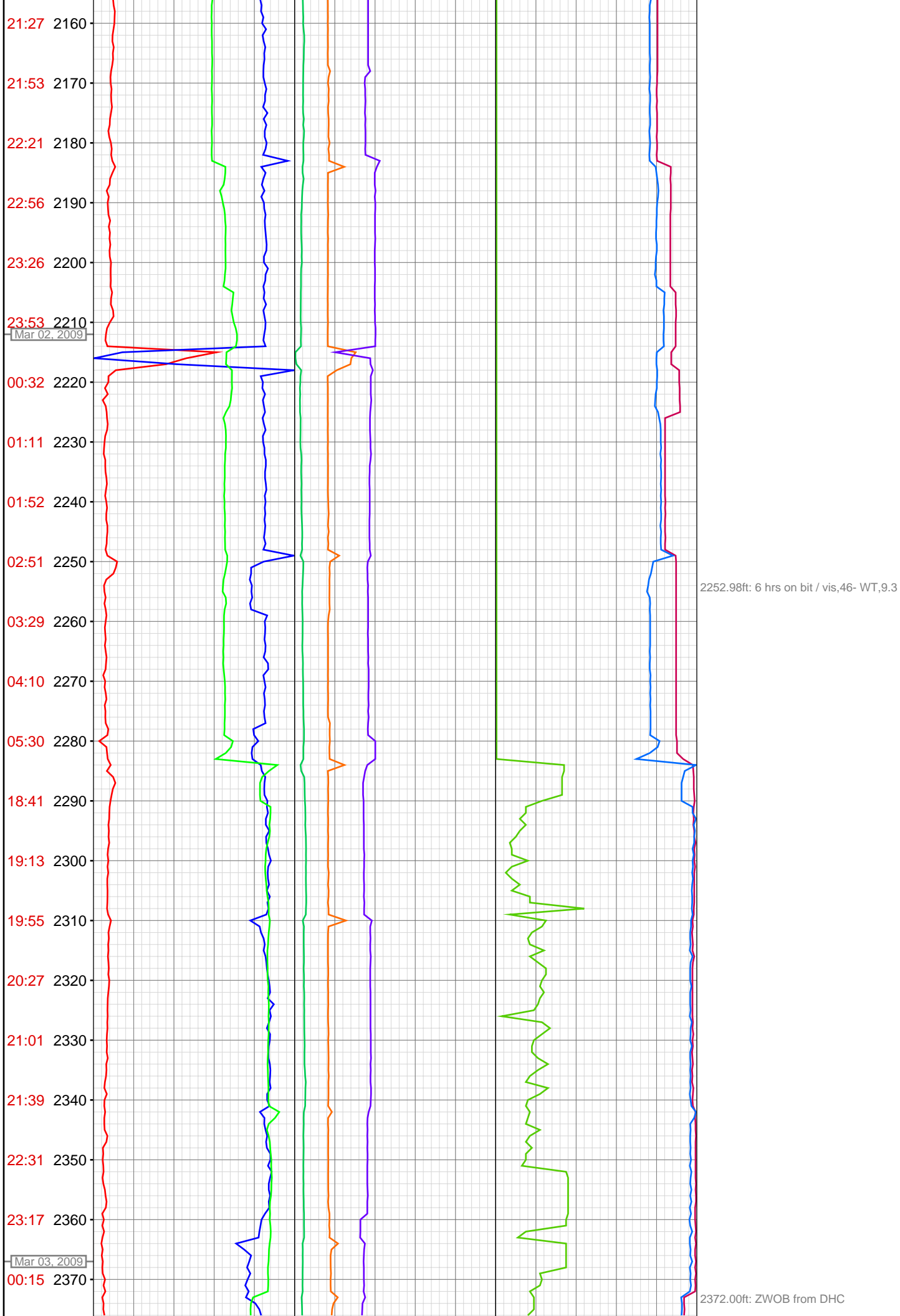


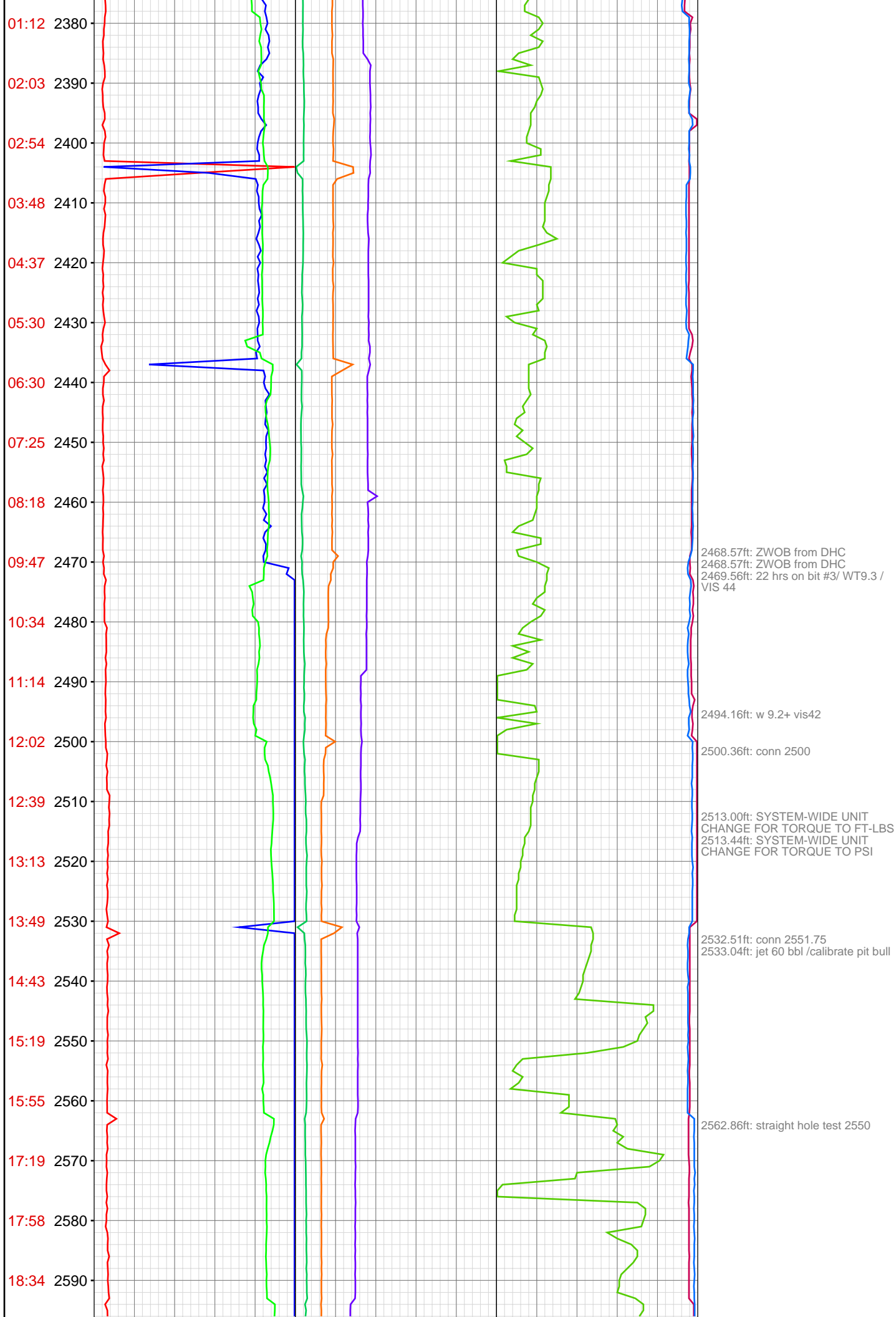


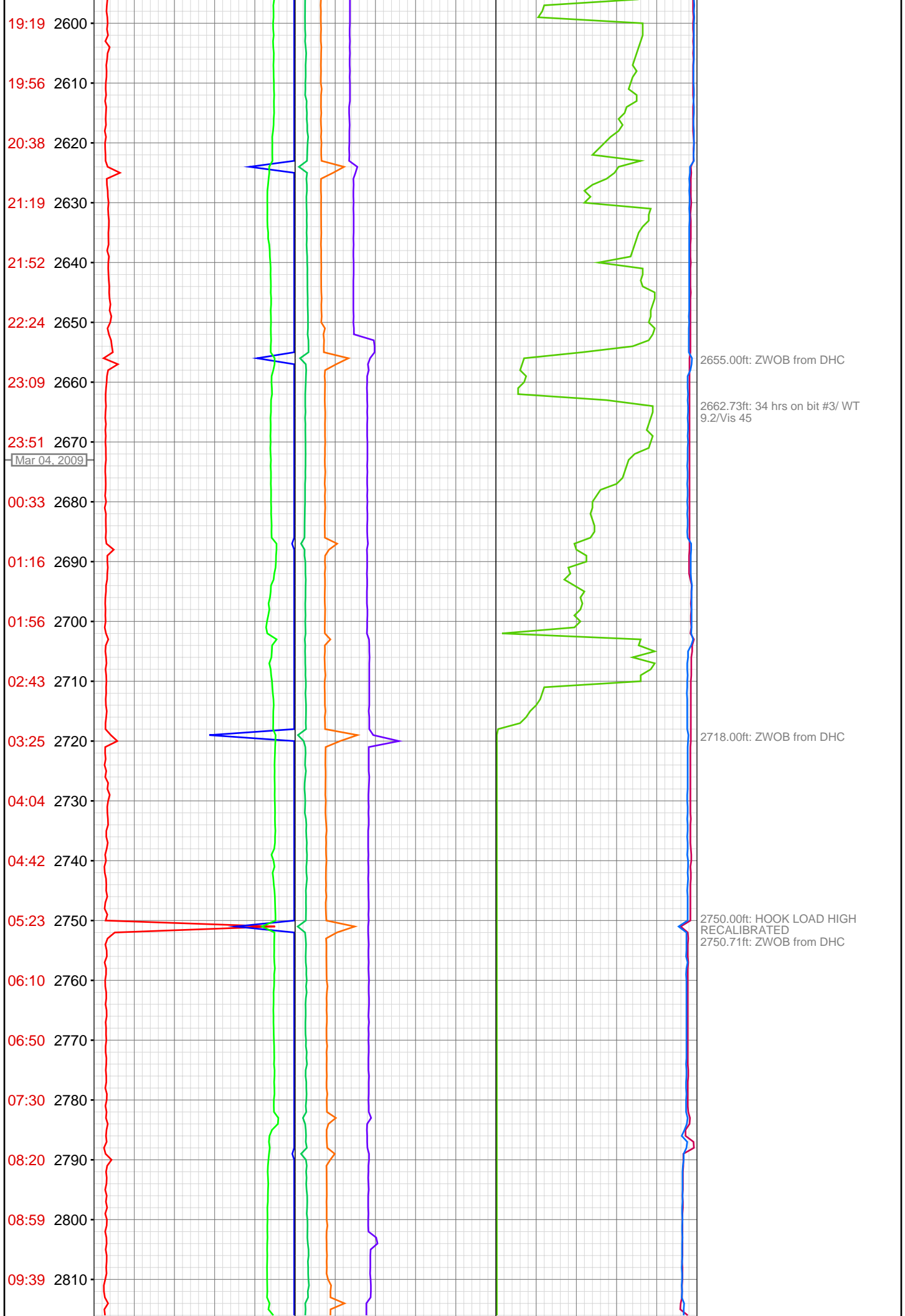


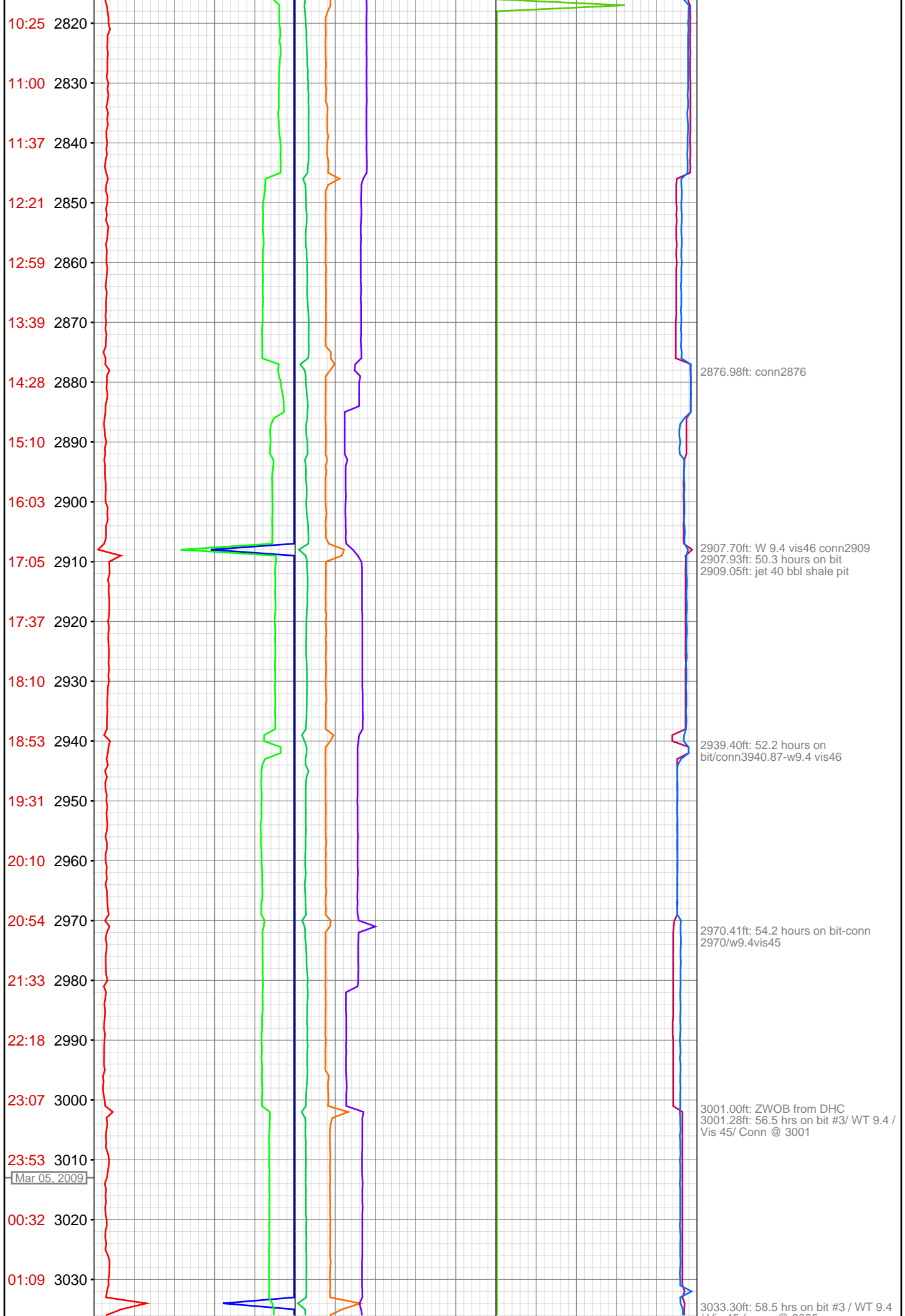


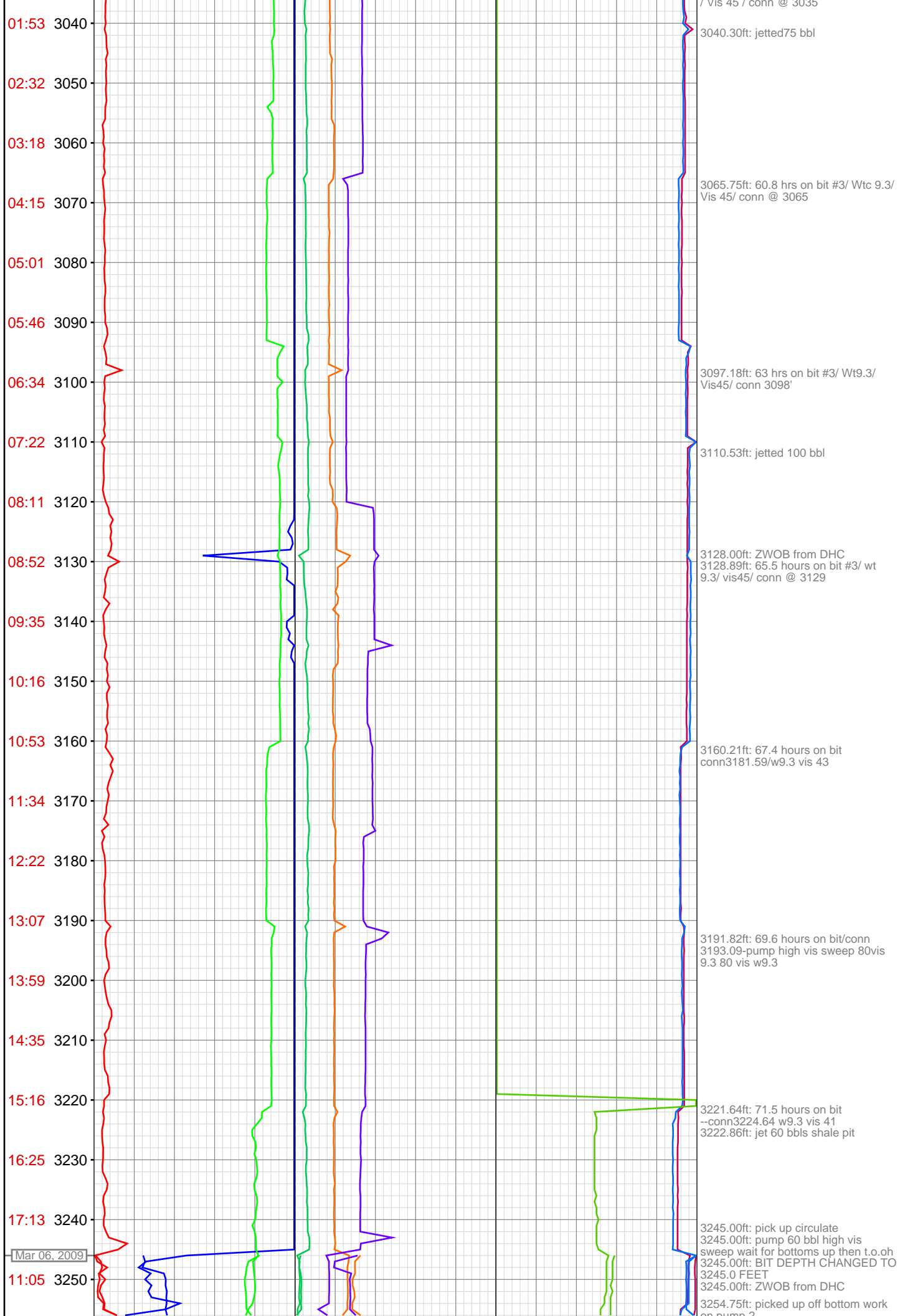


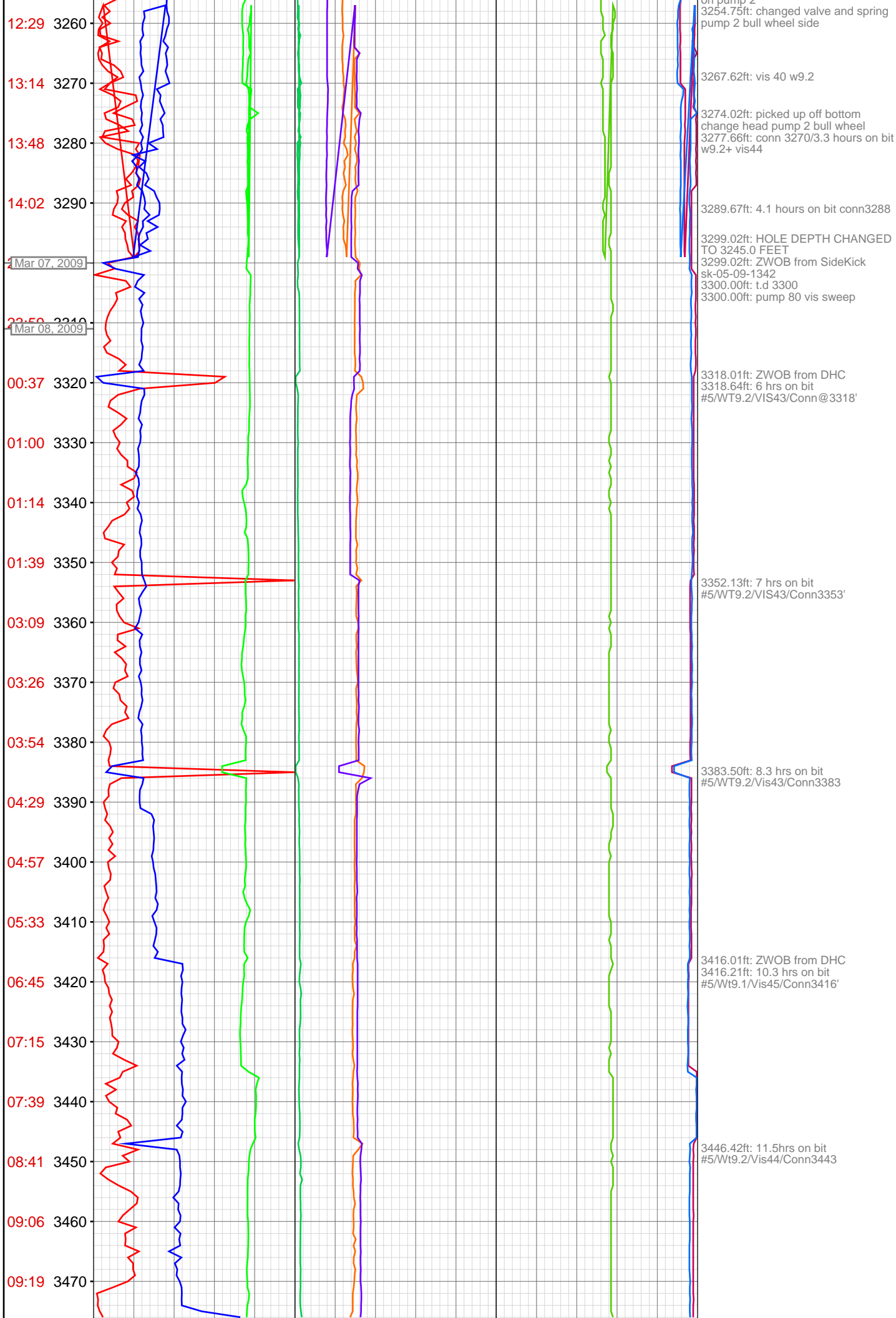


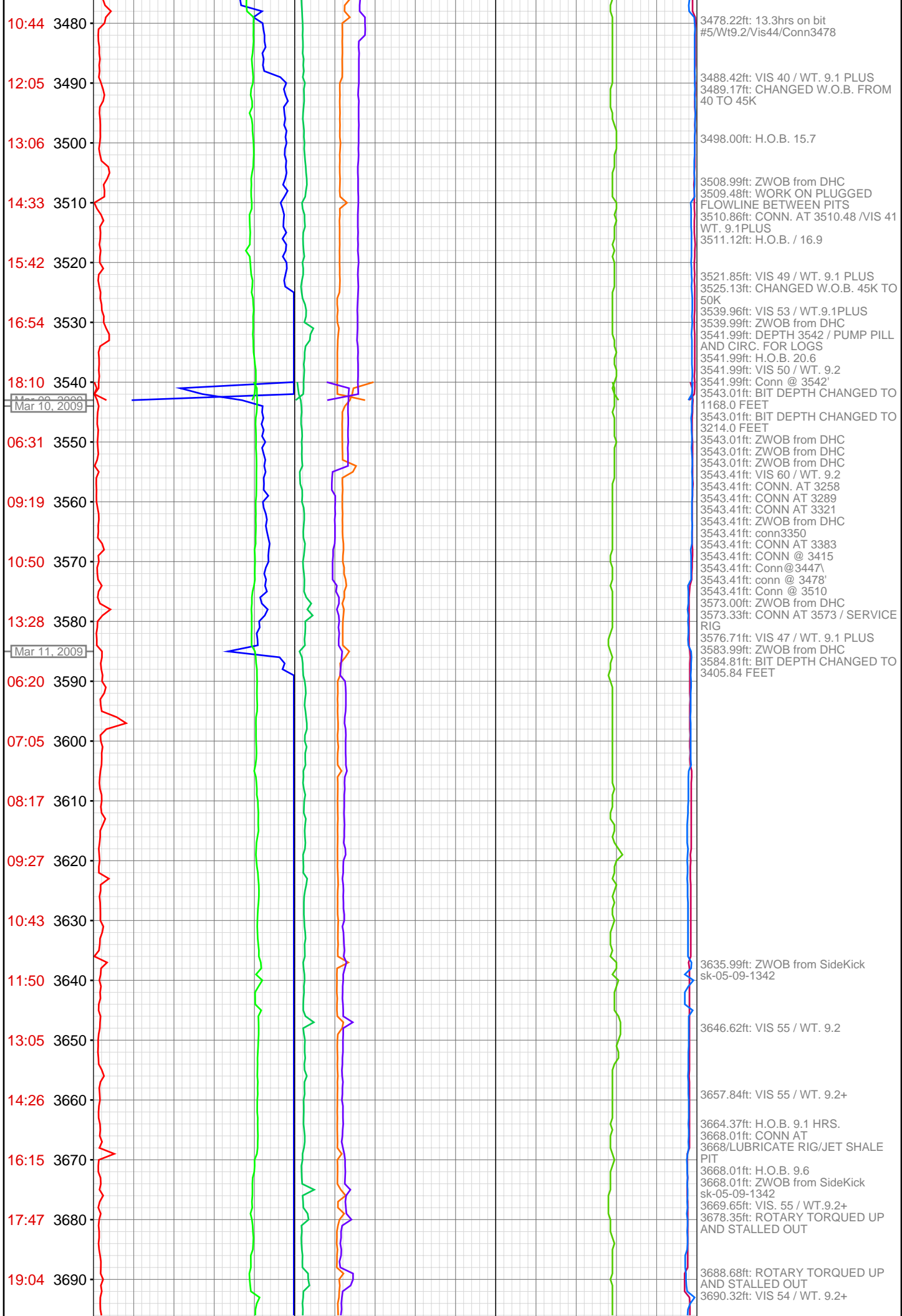


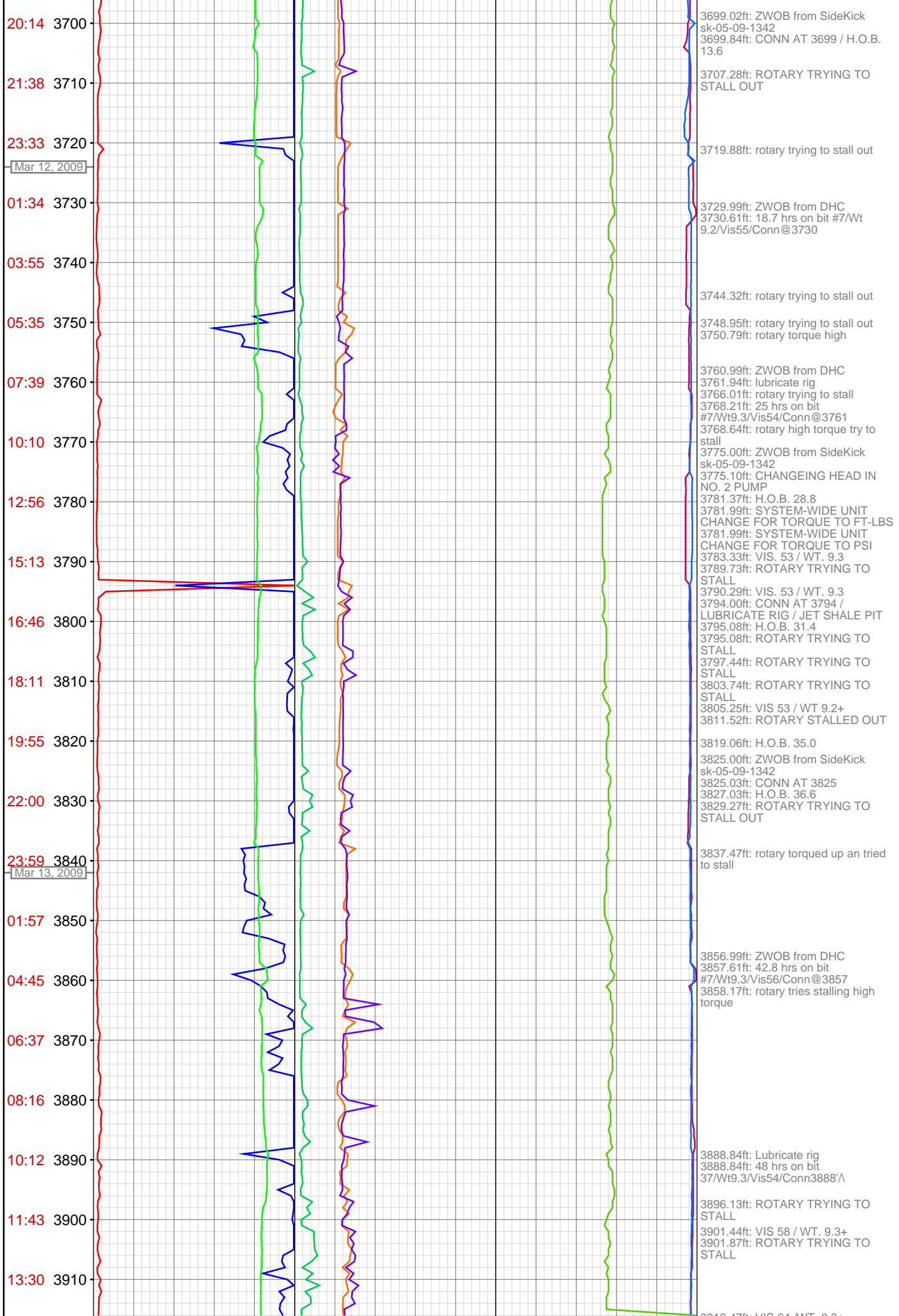


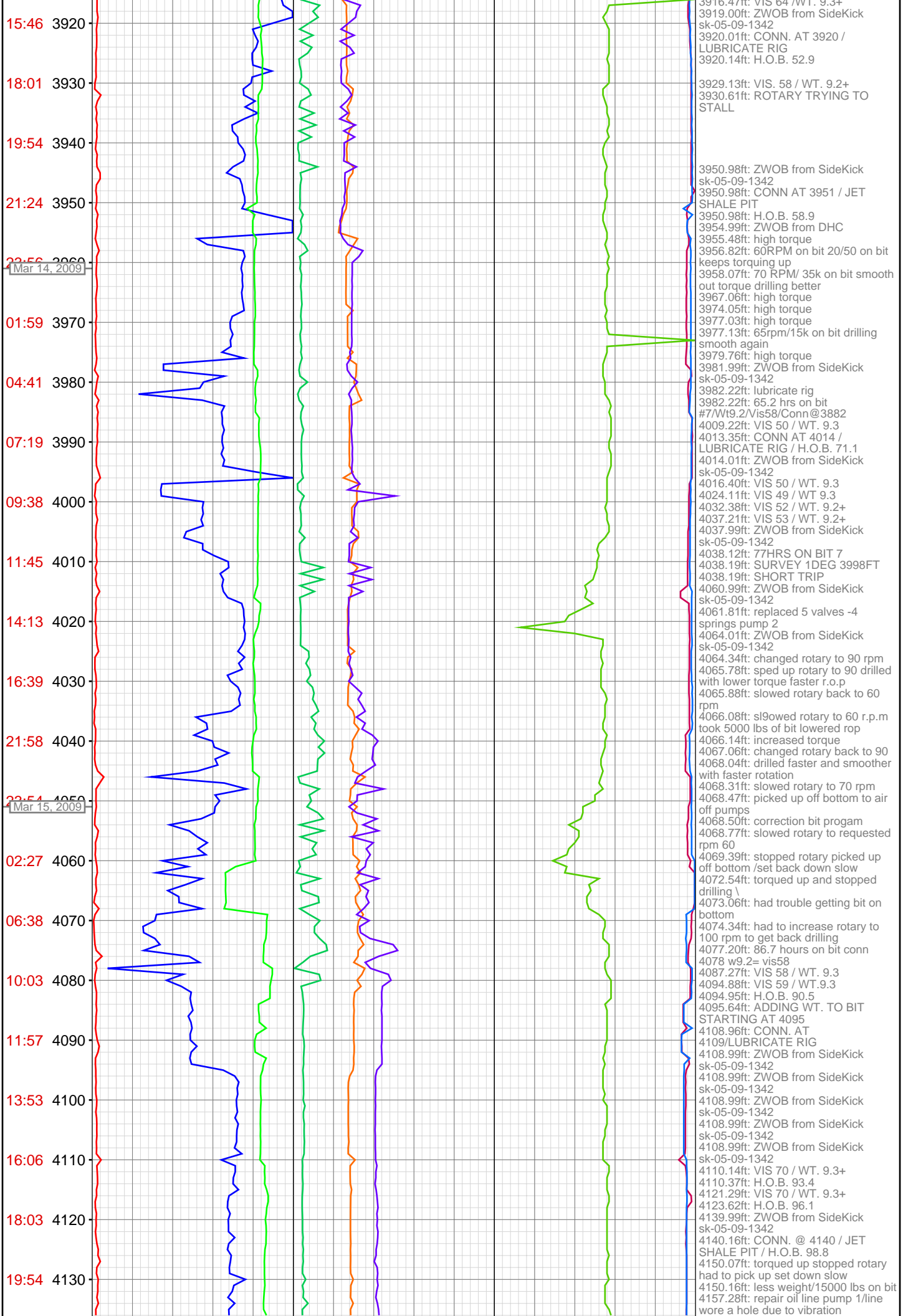


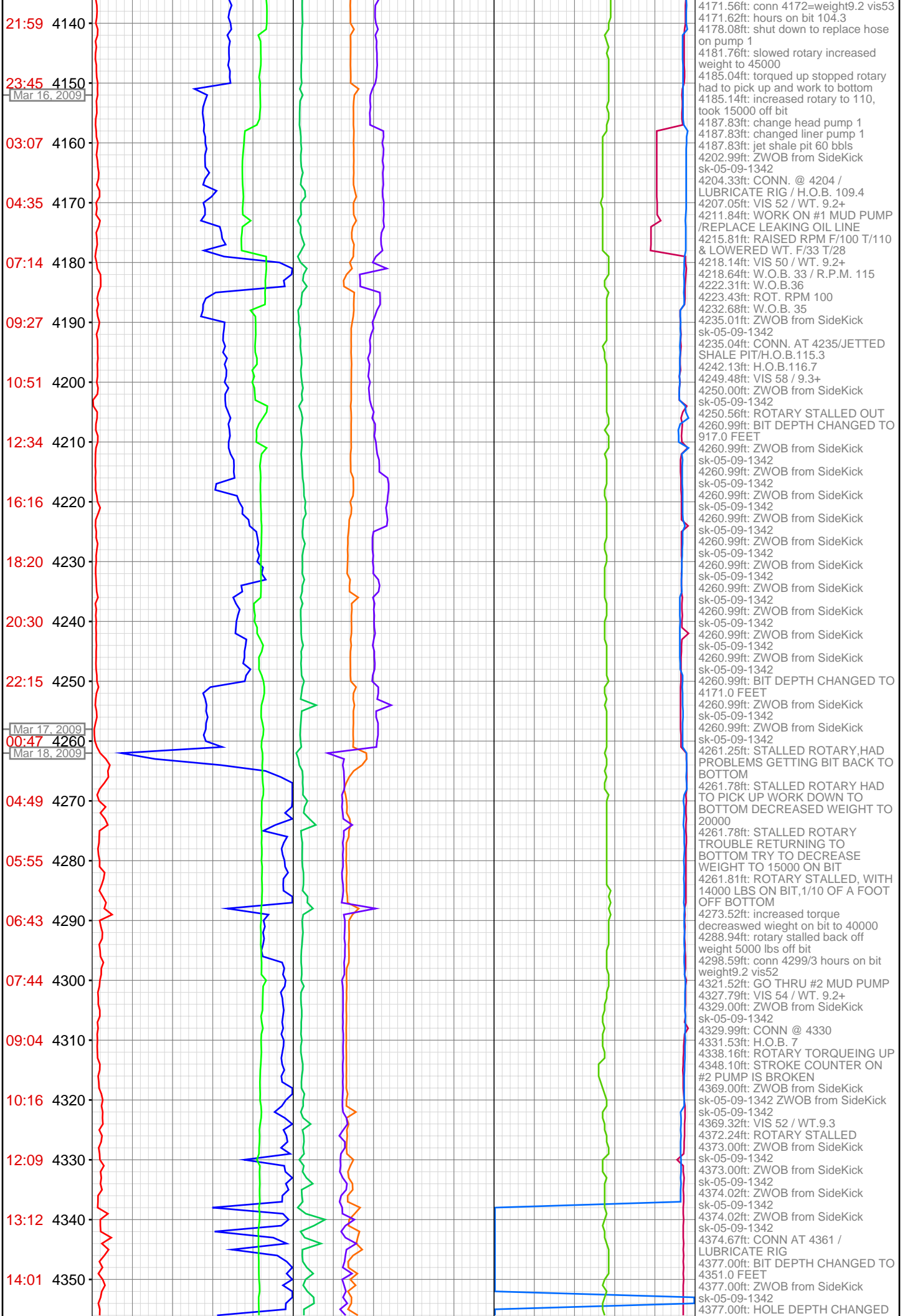


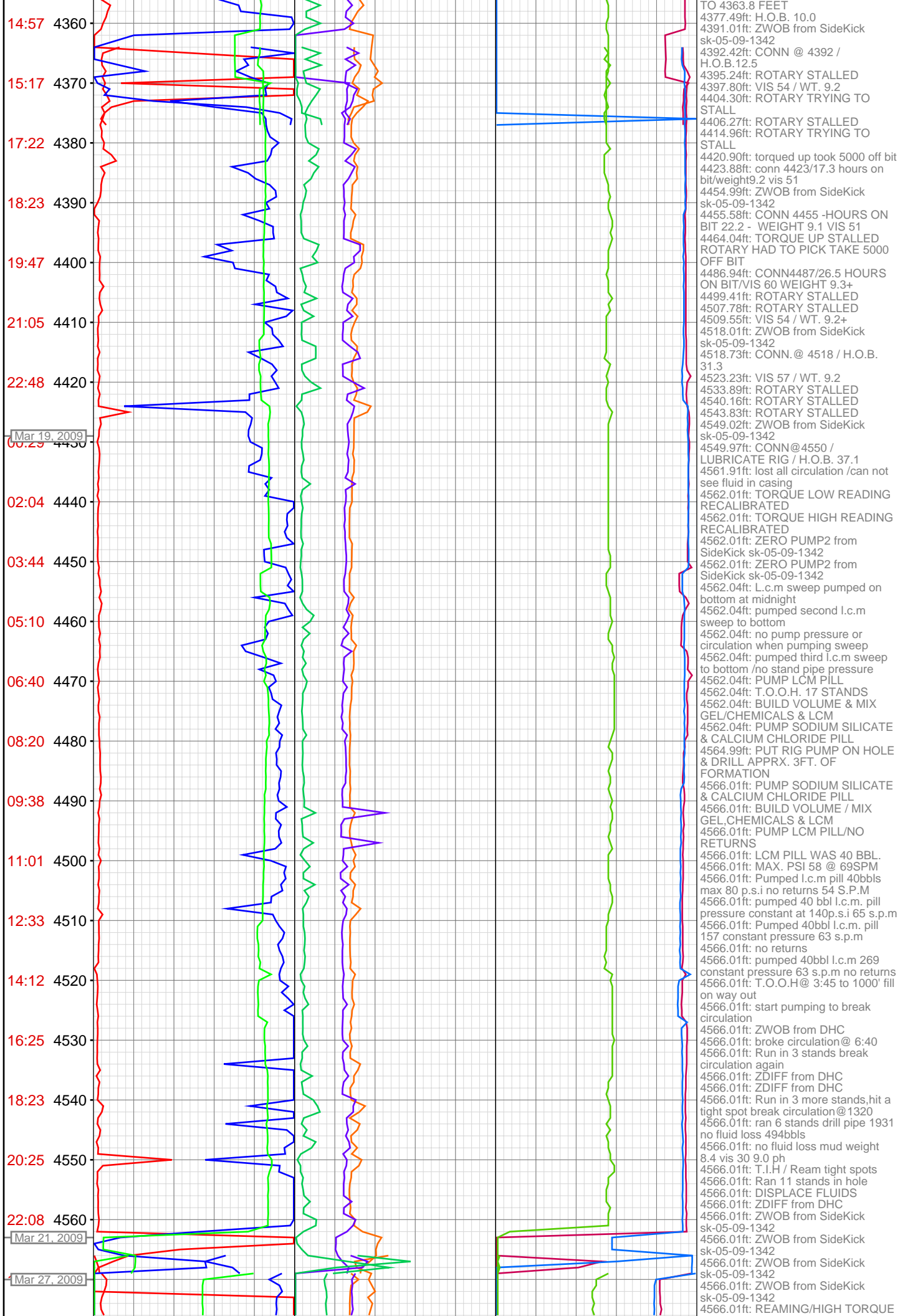


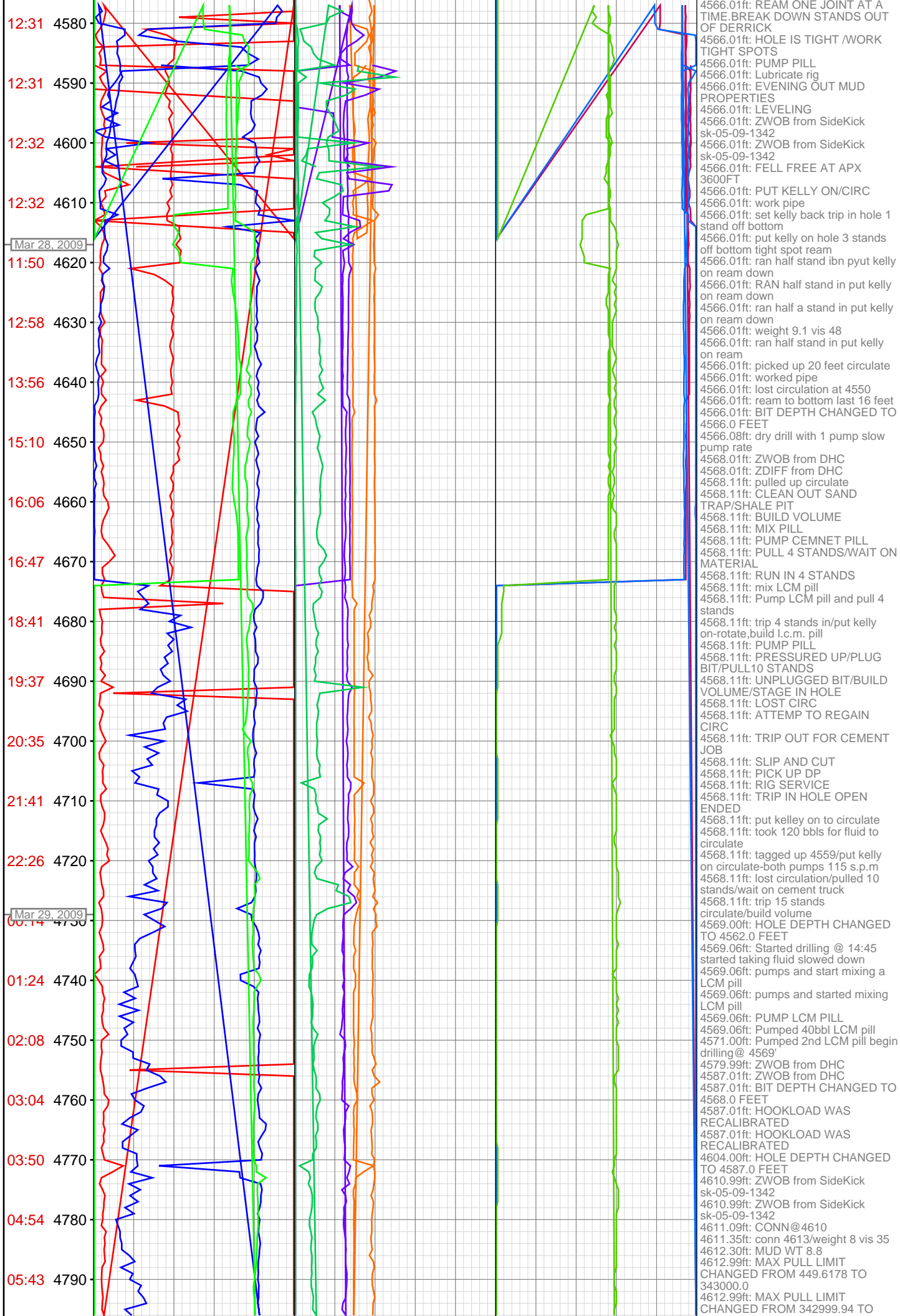


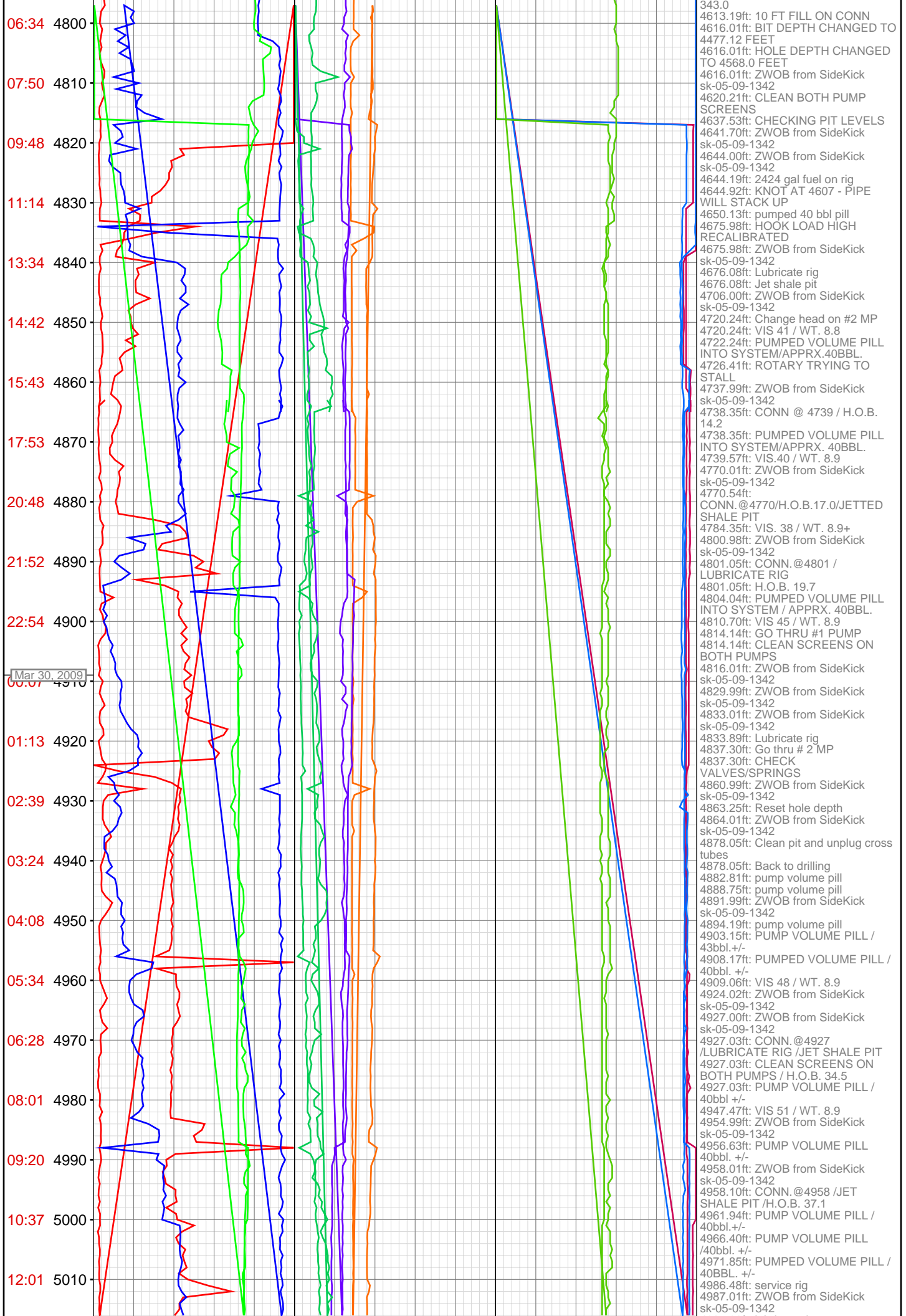


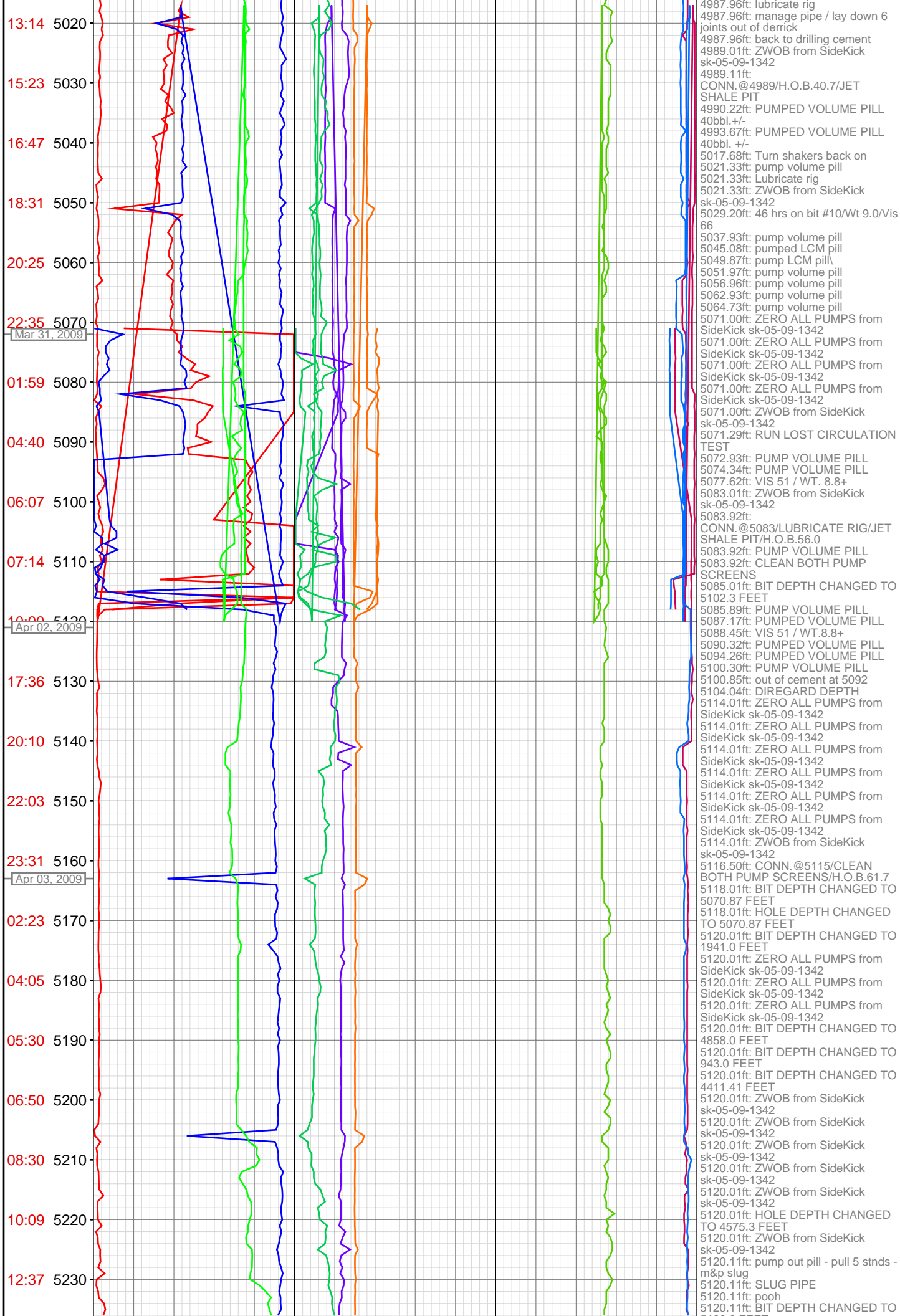


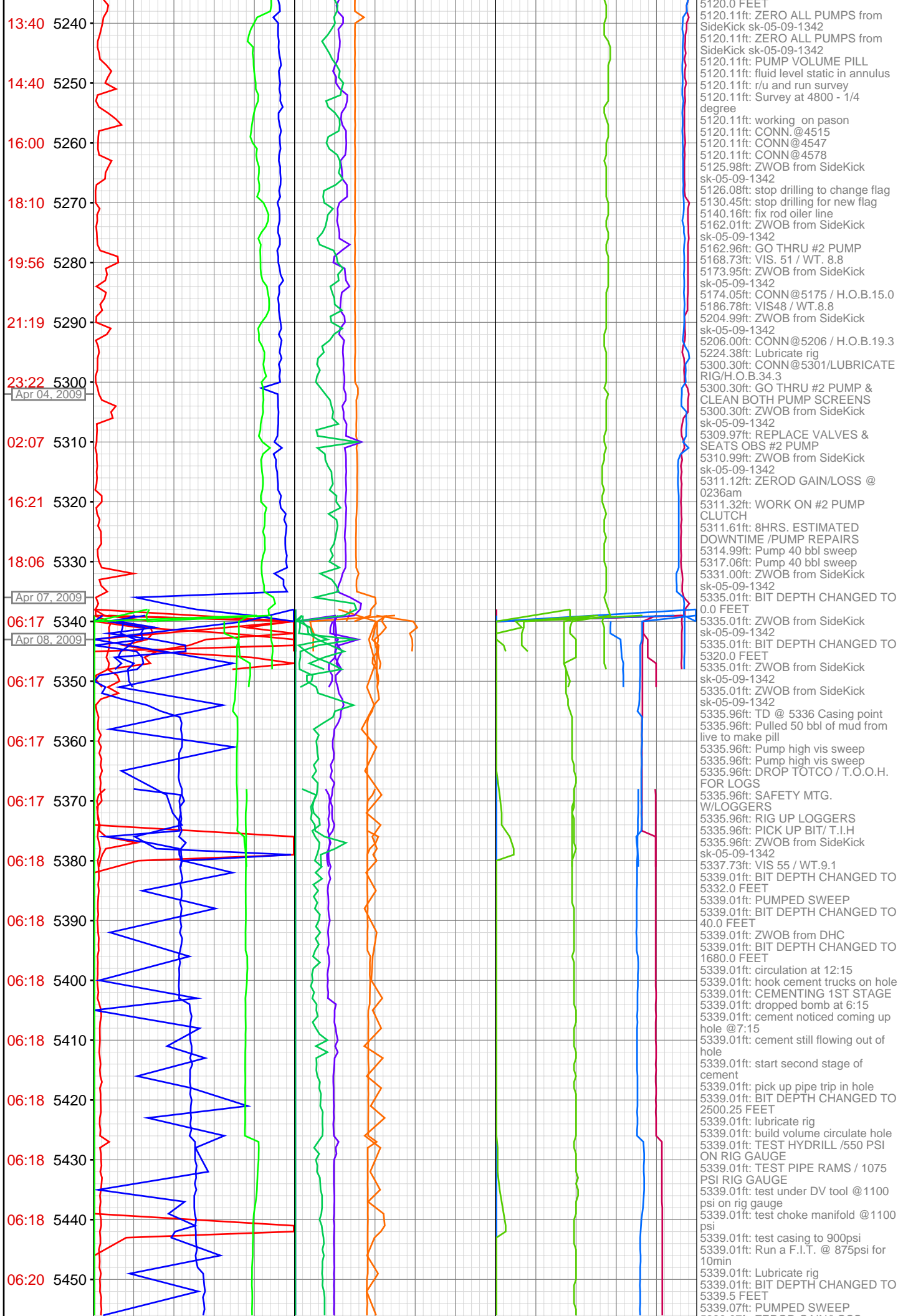


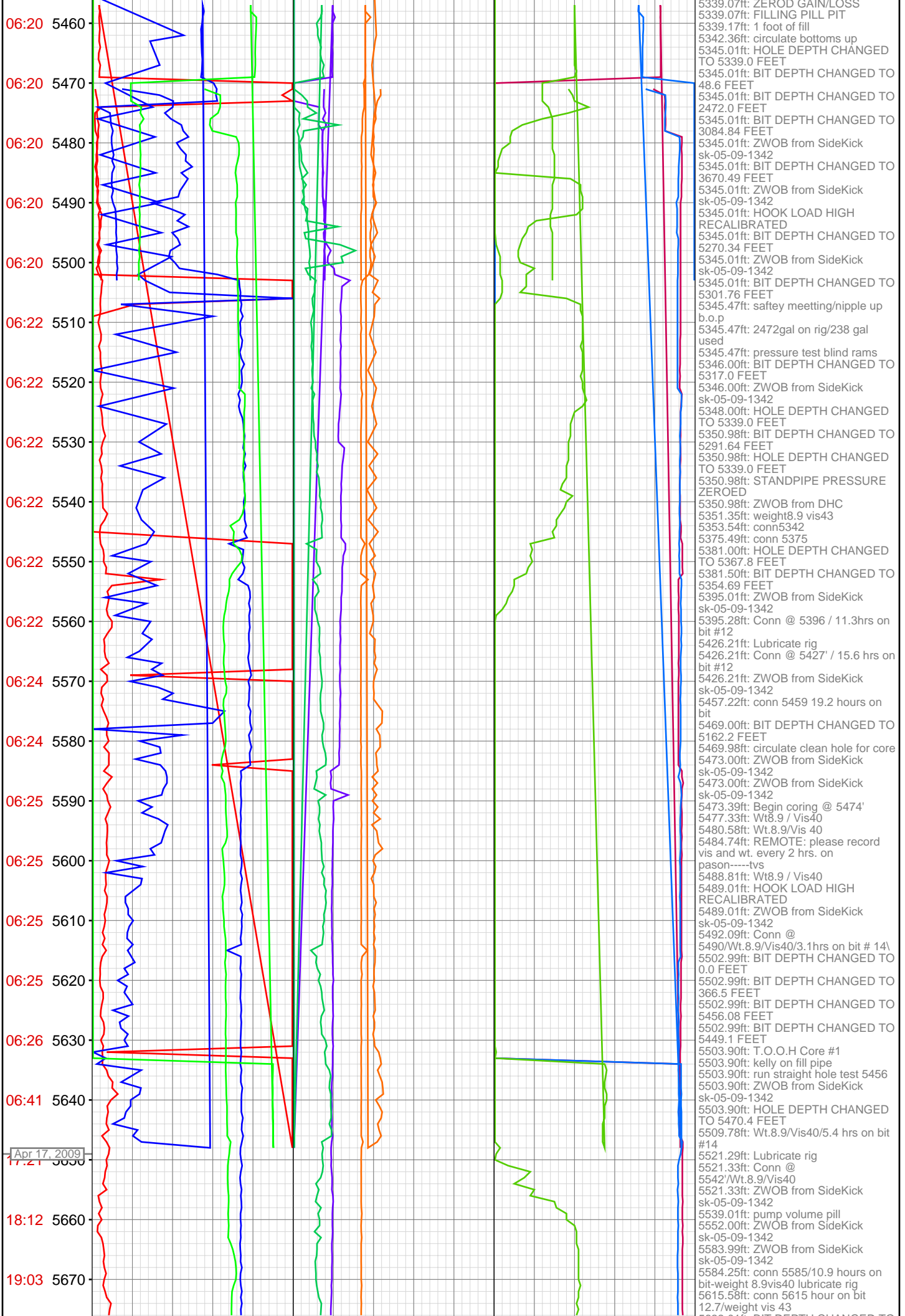


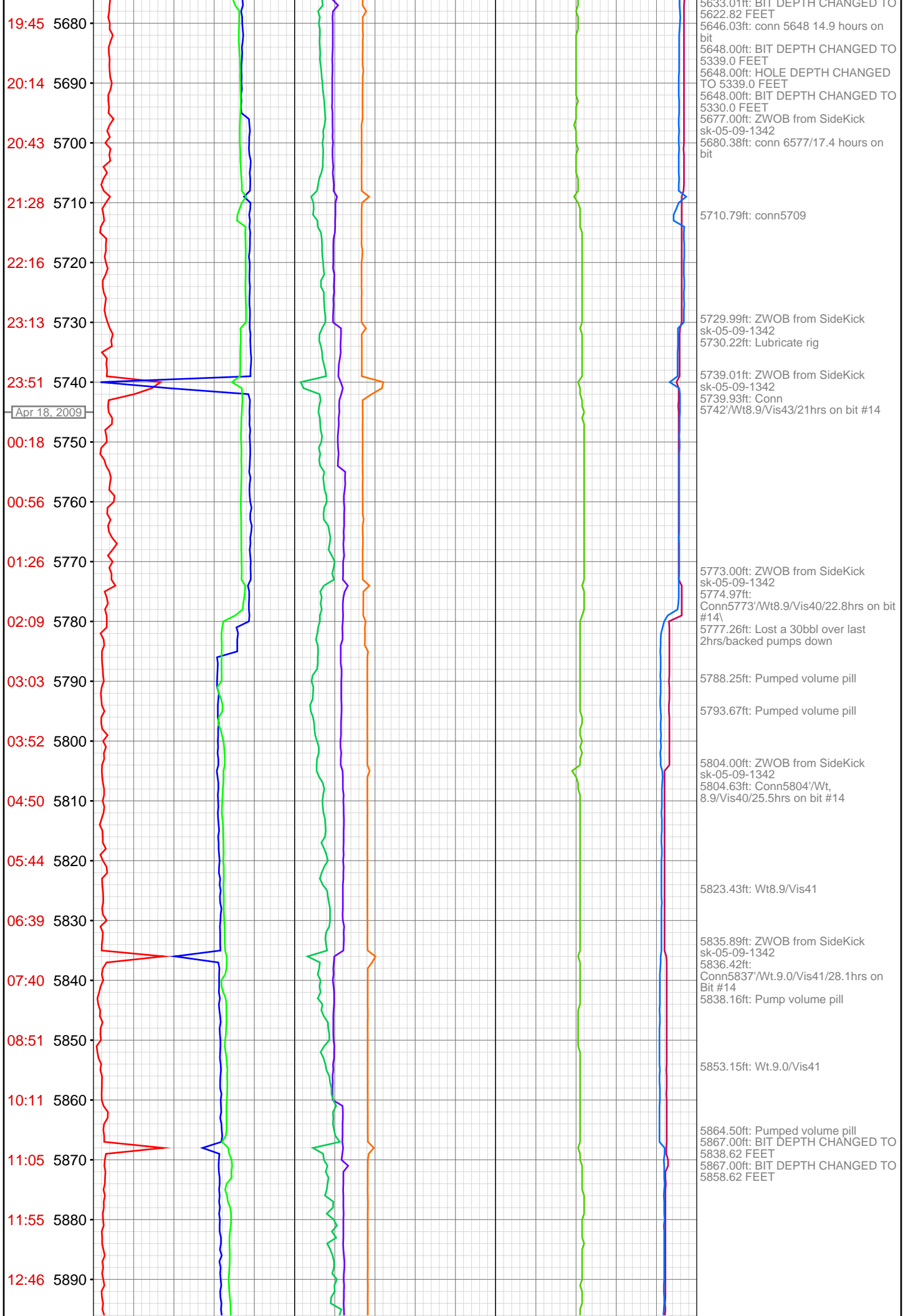


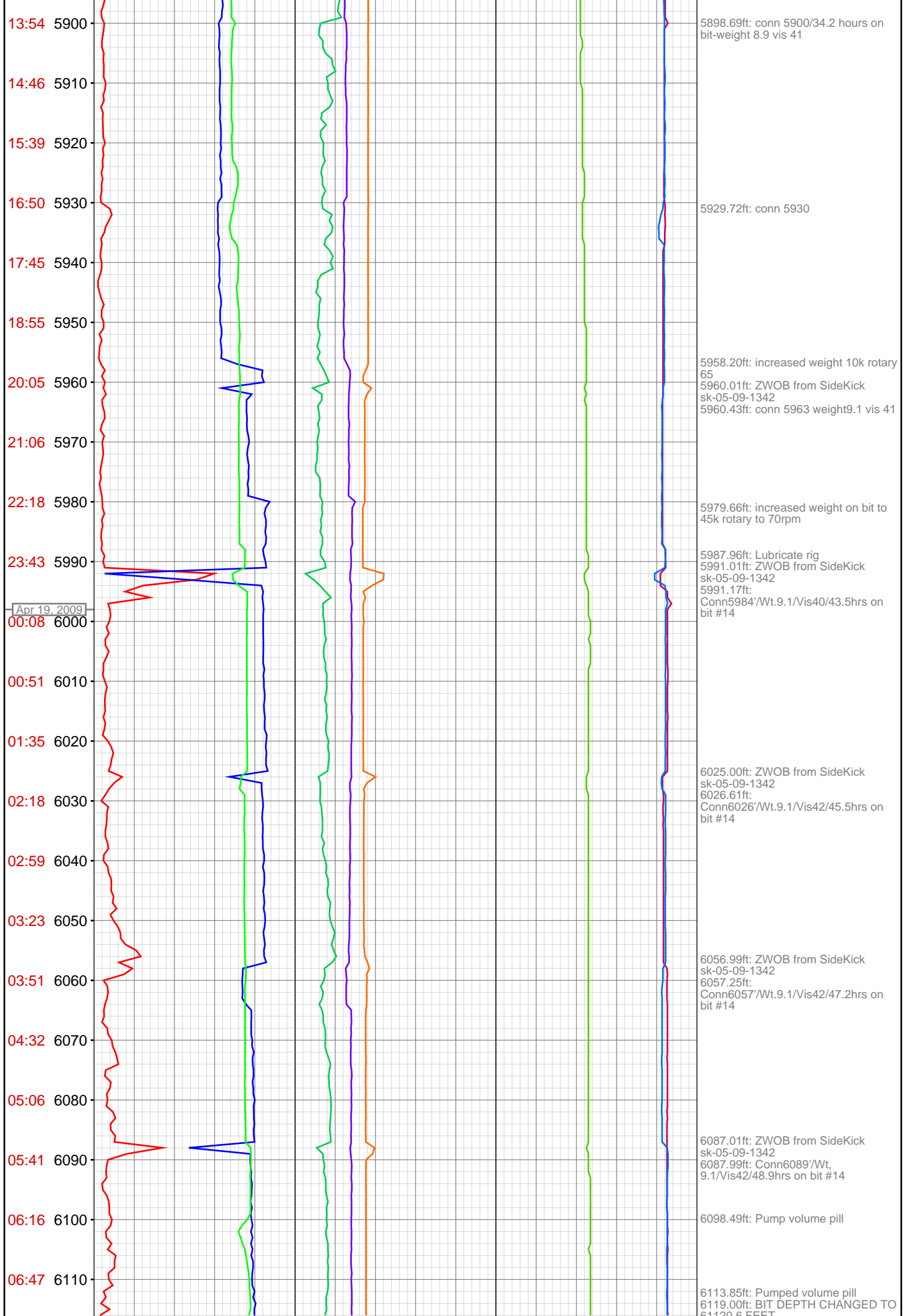


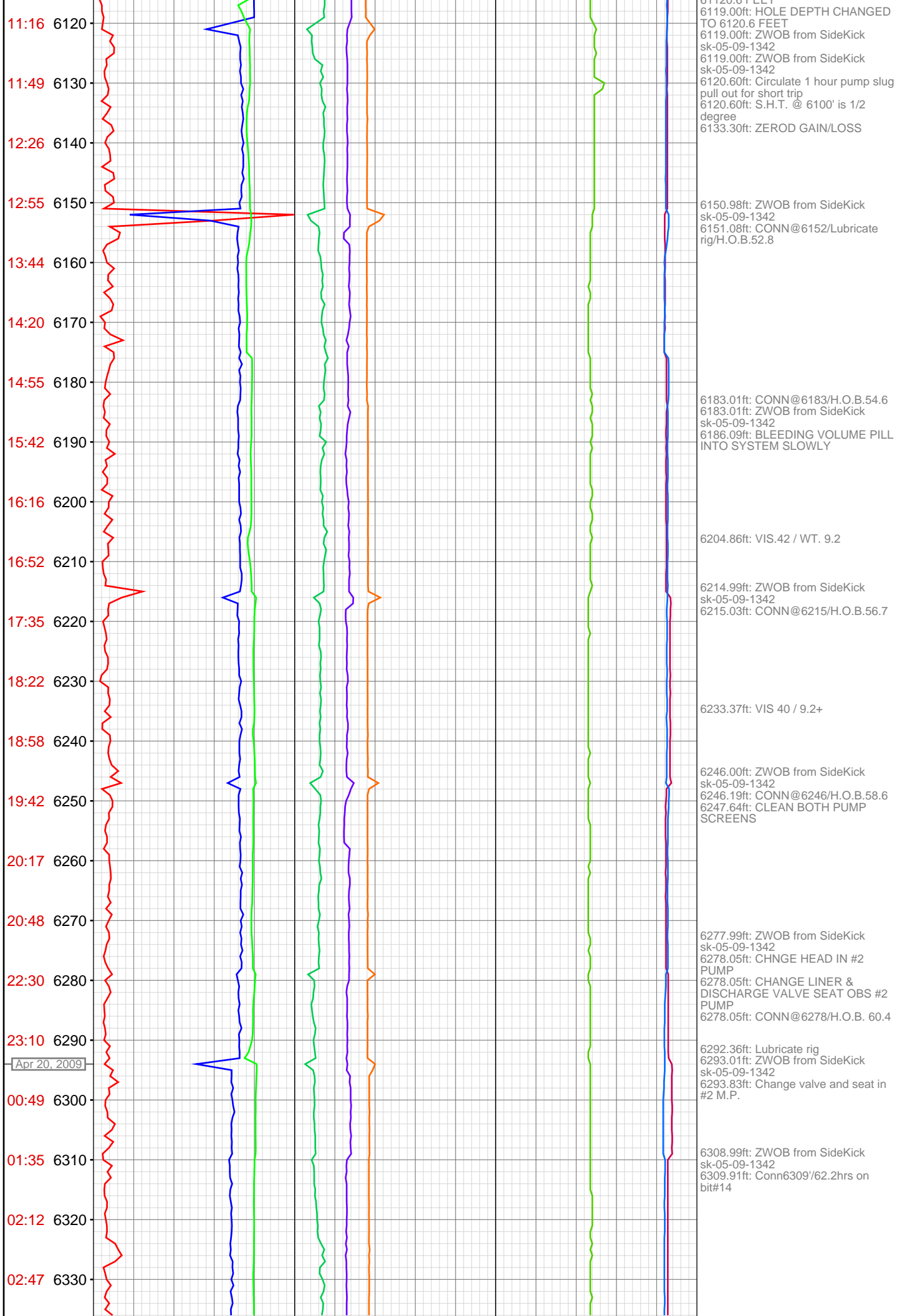


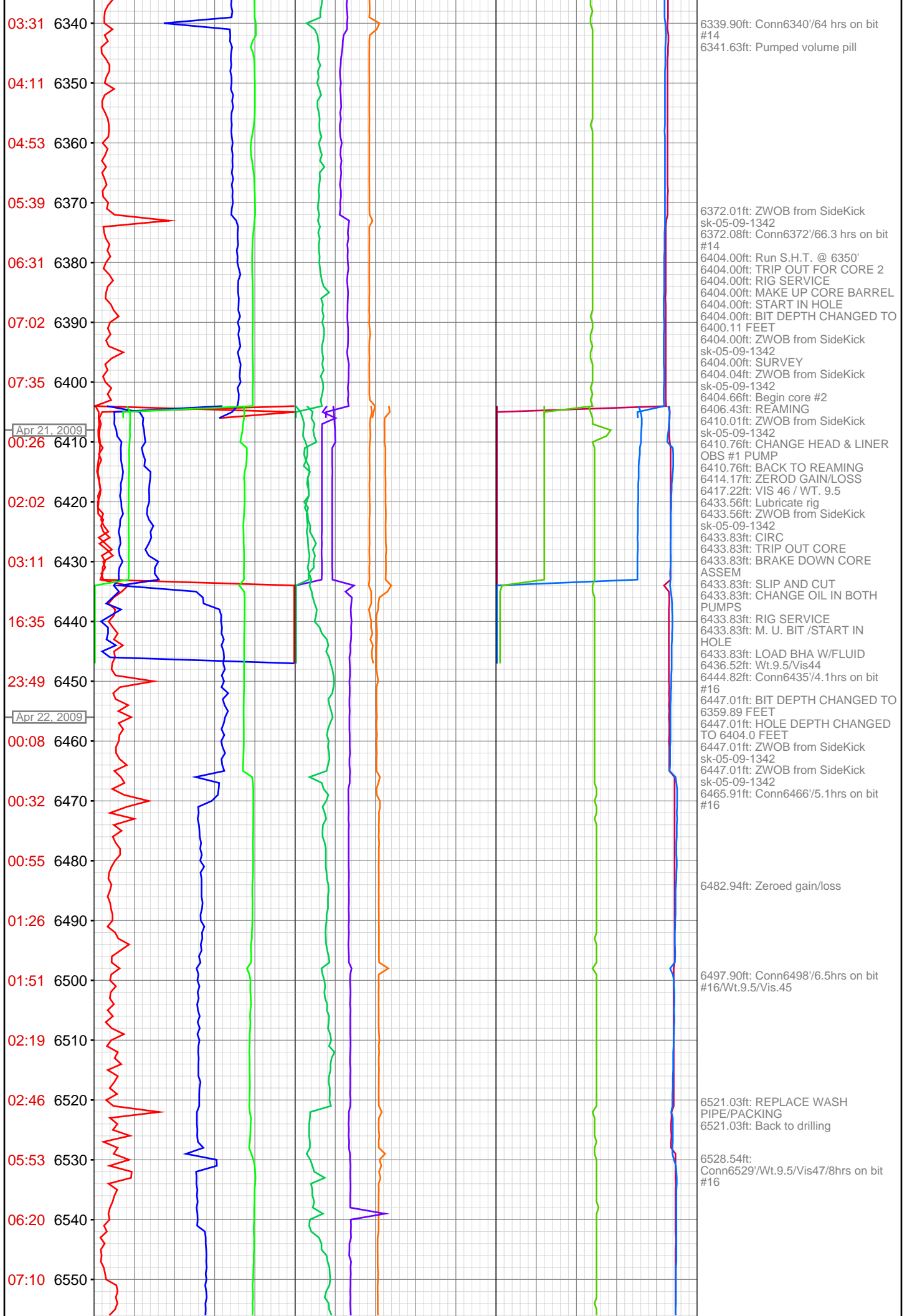


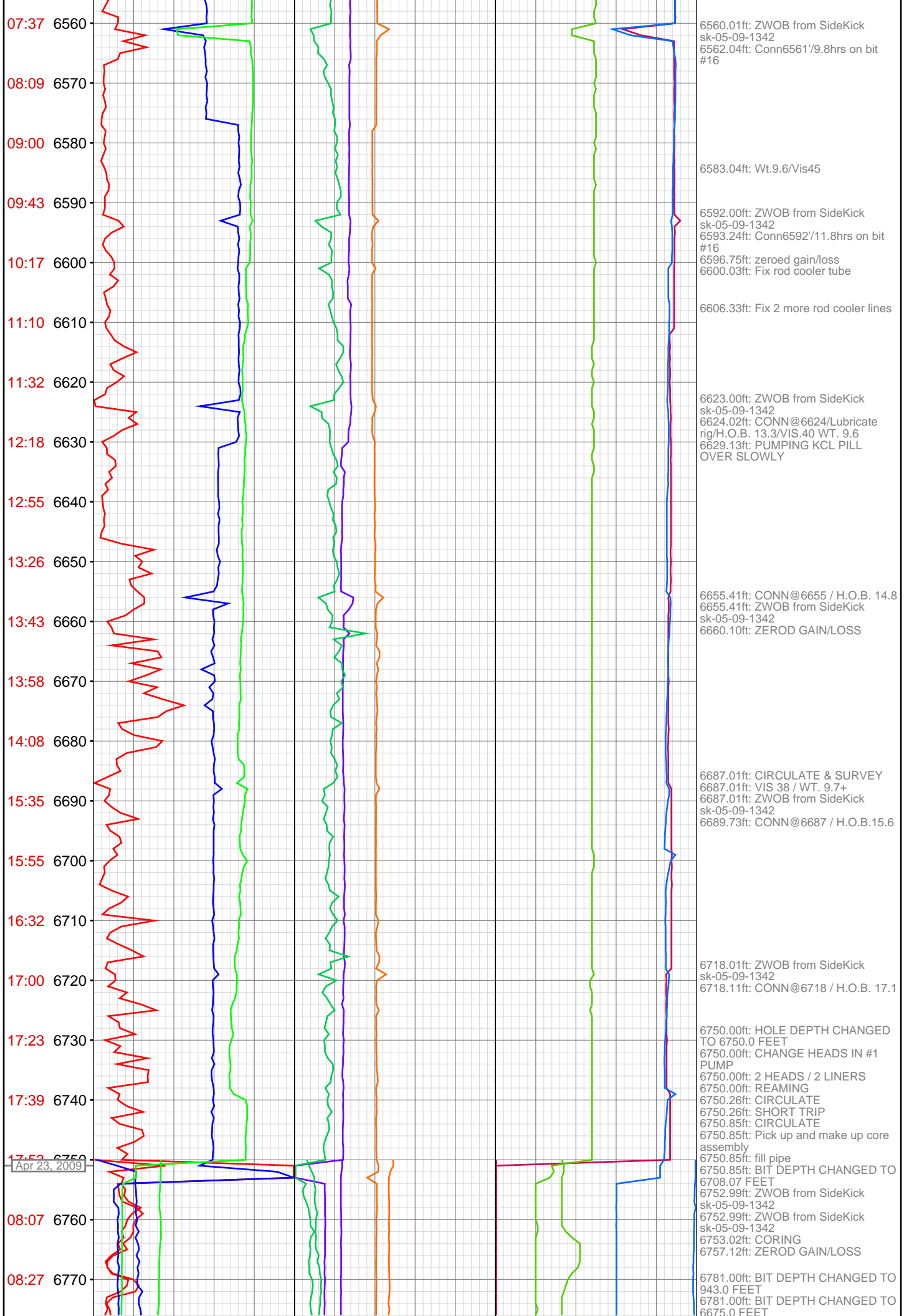


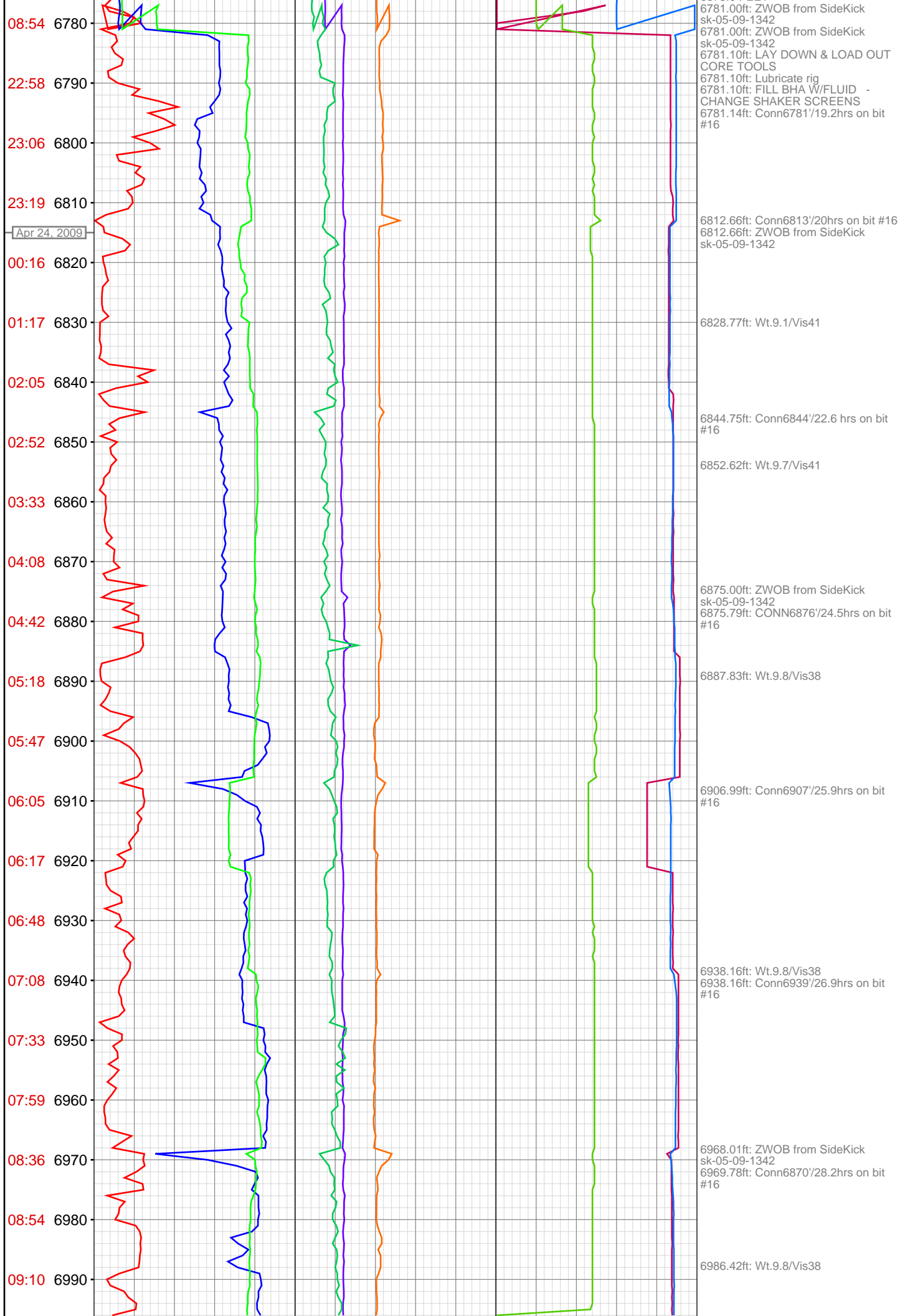


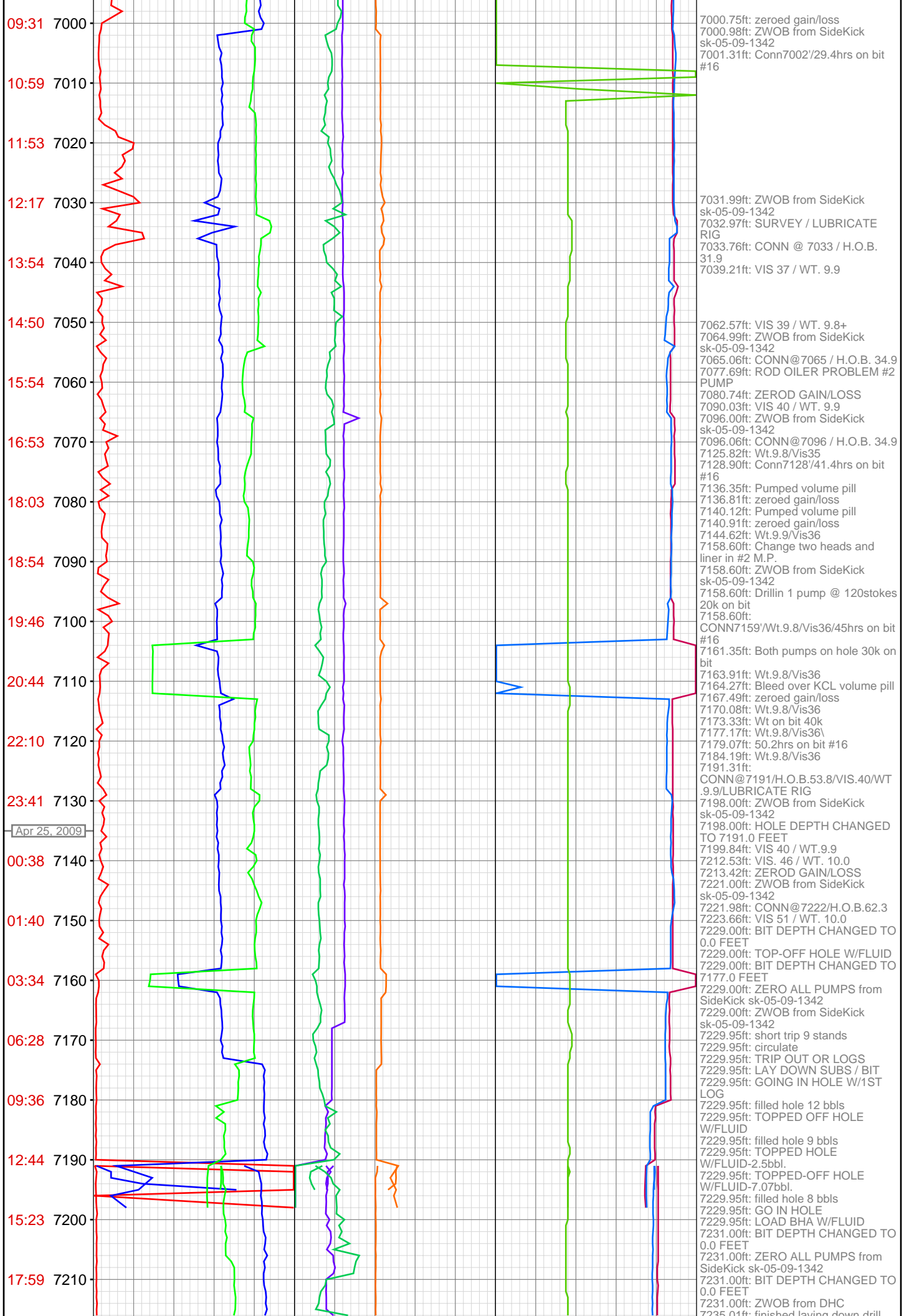


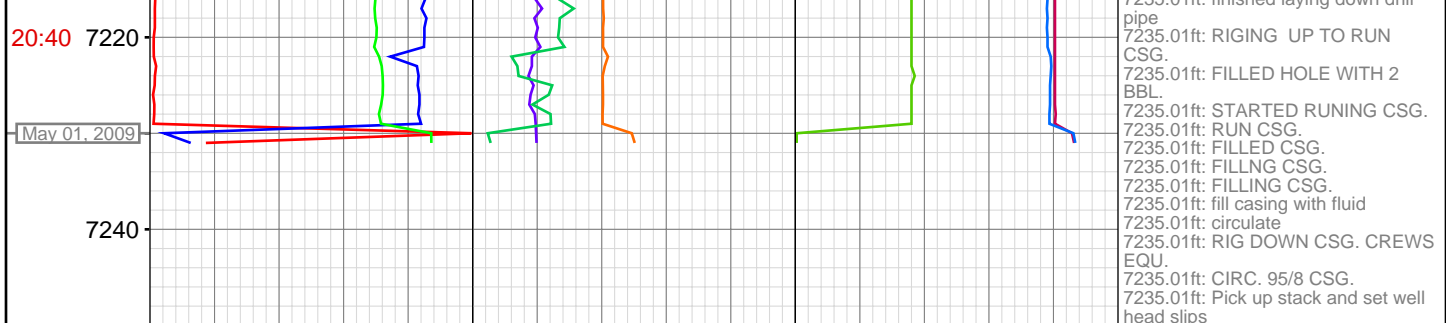












Appendix XI – Tallies of Installed Casing Strings

ADM CCS WELL #1: Surface Casing Tally						
Total Depth Tagged (ft):		355.00				
Joint #	Joint Length (ft)	Top Depth (ft)	Bottom Depth (ft)	Grade	Weight (lbs/ft)	Thread
1	44.88	310.12	355.00	H-40	94	8-round, STC
2	40.25	269.87	310.12	H-40	94	8-round, STC
3	41.67	228.20	269.87	H-40	94	8-round, STC
4	41.80	186.40	228.20	H-40	94	8-round, STC
5	41.56	144.84	186.40	H-40	94	8-round, STC
6	42.26	102.58	144.84	H-40	94	8-round, STC
7	42.97	59.61	102.58	H-40	94	8-round, STC
8	39.95	19.66	59.61	H-40	94	8-round, STC
9	40.74	-21.08	19.66	H-40	94	8-round, STC

ADM CCS WELL #1: Intermediate Casing Tally

Prepared by: PTH Jr/TG

Total Depth Tagged (ft): **5330** EST TD

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
Shoe	1.92	1.92	5328.08	5330.00				
1	38.46	40.38	5289.62	5328.08	J55	66.17	Butt	X
FC	1.33	41.71	5288.29	5289.62				
2	47.82	89.53	5240.47	5288.29	J55	66.17	Butt	X
3	46.85	136.38	5193.62	5240.47	J55	66.17	Butt	X
4	46.82	183.20	5146.80	5193.62	J55	66.17	Butt	X
5	46.93	230.13	5099.87	5146.80	J55	66.17	Butt	
6	46.30	276.43	5053.57	5099.87	J55	66.17	Butt	
7	42.18	318.61	5011.39	5053.57	J55	66.17	Butt	
8	46.71	365.32	4964.68	5011.39	J55	66.17	Butt	
9	43.10	408.42	4921.58	4964.68	J55	66.17	Butt	
10	42.05	450.47	4879.53	4921.58	J55	66.17	Butt	
11	46.69	497.16	4832.84	4879.53	J55	66.17	Butt	
12	42.00	539.16	4790.84	4832.84	J55	66.17	Butt	
13	41.41	580.57	4749.43	4790.84	J55	66.17	Butt	
14	44.83	625.40	4704.60	4749.43	J55	66.17	Butt	
15	46.52	671.92	4658.08	4704.60	J55	66.17	Butt	
16	41.48	713.40	4616.60	4658.08	J55	66.17	Butt	
17	37.61	751.01	4578.99	4616.60	J55	66.17	Butt	
18	40.33	791.34	4538.66	4578.99	J55	66.17	Butt	
19	46.03	837.37	4492.63	4538.66	J55	66.17	Butt	
20	44.45	881.82	4448.18	4492.63	J55	66.17	Butt	
21	46.98	928.80	4401.20	4448.18	J55	66.17	Butt	
22	46.73	975.53	4354.47	4401.20	J55	66.17	Butt	
23	42.68	1018.21	4311.79	4354.47	J55	66.17	Butt	
24	45.63	1063.84	4266.16	4311.79	J55	66.17	Butt	
25	46.83	1110.67	4219.33	4266.16	J55	66.17	Butt	
26	43.18	1153.85	4176.15	4219.33	J55	66.17	Butt	
27	46.61	1200.46	4129.54	4176.15	J55	66.17	Butt	
28	46.96	1247.42	4082.58	4129.54	J55	66.17	Butt	
29	47.18	1294.60	4035.40	4082.58	J55	66.17	Butt	
30	46.09	1340.69	3989.31	4035.40	J55	66.17	Butt	

ADM CCS WELL #1: Intermediate Casing Tally

** Stage tool 2.29' bottom of jt 37

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
31	46.78	1387.47	3942.53	3989.31	J55	66.17	Butt	
32	45.32	1432.79	3897.21	3942.53	J55	66.17	Butt	X
33	44.79	1477.58	3852.42	3897.21	J55	66.17	Butt	
34	46.63	1524.21	3805.79	3852.42	J55	66.17	Butt	X
35	46.77	1570.98	3759.02	3805.79	J55	66.17	Butt	
36	41.18	1612.16	3717.84	3759.02	J55	66.17	Butt	X
37	44.63	1656.79	3673.21	3717.84	J55	66.17	Butt	**
38	42.58	1699.37	3630.63	3673.21	J55	66.17	Butt	
39	44.78	1744.15	3585.85	3630.63	J55	59.50	Butt	
40	41.82	1785.97	3544.03	3585.85	J55	59.50	Butt	Bskt
41	44.75	1830.72	3499.28	3544.03	J55	59.50	Butt	
42	43.78	1874.50	3455.50	3499.28	J55	59.50	Butt	
43	43.00	1917.50	3412.50	3455.50	J55	59.50	Butt	
44	43.95	1961.45	3368.55	3412.50	J55	59.50	Butt	
45	40.14	2001.59	3328.41	3368.55	J55	59.50	Butt	
46	44.19	2045.78	3284.22	3328.41	J55	59.50	Butt	
47	41.00	2086.78	3243.22	3284.22	J55	59.50	Butt	
48	44.68	2131.46	3198.54	3243.22	J55	59.50	Butt	
49	44.78	2176.24	3153.76	3198.54	J55	59.50	Butt	
50	41.50	2217.74	3112.26	3153.76	J55	59.50	Butt	
51	41.56	2259.30	3070.70	3112.26	J55	59.50	Butt	
52	44.23	2303.53	3026.47	3070.70	J55	59.50	Butt	
53	41.01	2344.54	2985.46	3026.47	J55	59.50	Butt	
54	44.73	2389.27	2940.73	2985.46	J55	59.50	Butt	
55	40.95	2430.22	2899.78	2940.73	J55	59.50	Butt	
56	40.60	2470.82	2859.18	2899.78	J55	59.50	Butt	
57	40.22	2511.04	2818.96	2859.18	J55	59.50	Butt	
58	41.40	2552.44	2777.56	2818.96	J55	59.50	Butt	
59	44.72	2597.16	2732.84	2777.56	J55	59.50	Butt	
60	41.48	2638.64	2691.36	2732.84	J55	59.50	Butt	

ADM CCS WELL #1: Intermediate Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
61	43.10	2681.74	2648.26	2691.36	J55	59.50	Butt	
62	40.94	2722.68	2607.32	2648.26	J55	59.50	Butt	X
63	41.03	2763.71	2566.29	2607.32	J55	59.50	Butt	
64	44.90	2808.61	2521.39	2566.29	J55	59.50	Butt	
65	44.16	2852.77	2477.23	2521.39	J55	59.50	Butt	X
66	40.68	2893.45	2436.55	2477.23	J55	59.50	Butt	
67	40.94	2934.39	2395.61	2436.55	J55	59.50	Butt	
68	40.63	2975.02	2354.98	2395.61	J55	59.50	Butt	X
69	44.66	3019.68	2310.32	2354.98	J55	59.50	Butt	
70	43.22	3062.90	2267.10	2310.32	J55	59.50	Butt	
71	40.80	3103.70	2226.30	2267.10	J55	59.50	Butt	
72	43.96	3147.66	2182.34	2226.30	J55	59.50	Butt	
73	41.68	3189.34	2140.66	2182.34	J55	59.50	Butt	
74	41.14	3230.48	2099.52	2140.66	J55	59.50	Butt	
75	44.21	3274.69	2055.31	2099.52	J55	59.50	Butt	
76	41.31	3316.00	2014.00	2055.31	J55	59.50	Butt	
77	44.34	3360.34	1969.66	2014.00	J55	59.50	Butt	
78	44.10	3404.44	1925.56	1969.66	J55	59.50	Butt	
79	44.27	3448.71	1881.29	1925.56	J55	59.50	Butt	
80	43.80	3492.51	1837.49	1881.29	J55	59.50	Butt	
81	44.32	3536.83	1793.17	1837.49	J55	59.50	Butt	
82	44.28	3581.11	1748.89	1793.17	J55	59.50	Butt	
83	42.91	3624.02	1705.98	1748.89	J55	59.50	Butt	
84	40.30	3664.32	1665.68	1705.98	J55	59.50	Butt	
85	41.08	3705.40	1624.60	1665.68	J55	59.50	Butt	
86	42.08	3747.48	1582.52	1624.60	J55	59.50	Butt	
87	41.20	3788.68	1541.32	1582.52	J55	59.50	Butt	
88	43.36	3832.04	1497.96	1541.32	J55	59.50	Butt	
89	44.78	3876.82	1453.18	1497.96	J55	59.50	Butt	
90	44.72	3921.54	1408.46	1453.18	J55	59.50	Butt	

ADM CCS WELL #1: Intermediate Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
91	44.00	3965.54	1364.46	1408.46	J55	59.50	Butt	
92	41.13	4006.67	1323.33	1364.46	J55	59.50	Butt	
93	39.95	4046.62	1283.38	1323.33	J55	59.50	Butt	
94	41.20	4087.82	1242.18	1283.38	J55	59.50	Butt	
95	41.58	4129.40	1200.60	1242.18	J55	59.50	Butt	
96	43.56	4172.96	1157.04	1200.60	J55	59.50	Butt	
97	44.68	4217.64	1112.36	1157.04	J55	59.50	Butt	
98	44.68	4262.32	1067.68	1112.36	J55	59.50	Butt	
99	41.26	4303.58	1026.42	1067.68	J55	59.50	Butt	
100	41.27	4344.85	985.15	1026.42	J55	59.50	Butt	
101	44.68	4389.53	940.47	985.15	J55	59.50	Butt	
102	44.68	4434.21	895.79	940.47	J55	59.50	Butt	
103	43.91	4478.12	851.88	895.79	J55	59.50	Butt	
104	42.90	4521.02	808.98	851.88	J55	59.50	Butt	
105	41.54	4562.56	767.44	808.98	J55	59.50	Butt	
106	44.60	4607.16	722.84	767.44	J55	59.50	Butt	
107	44.43	4651.59	678.41	722.84	J55	59.50	Butt	
108	38.85	4690.44	639.56	678.41	J55	59.50	Butt	
109	44.45	4734.89	595.11	639.56	J55	59.50	Butt	
110	40.30	4775.19	554.81	595.11	J55	59.50	Butt	
111	44.70	4819.89	510.11	554.81	J55	59.50	Butt	
112	44.80	4864.69	465.31	510.11	J55	59.50	Butt	
113	42.86	4907.55	422.45	465.31	J55	59.50	Butt	
114	41.27	4948.82	381.18	422.45	J55	59.50	Butt	
115	43.48	4992.30	337.70	381.18	J55	59.50	Butt	
116	41.25	5033.55	296.45	337.70	J55	59.50	Butt	
117	41.26	5074.81	255.19	296.45	J55	59.50	Butt	
118	44.70	5119.51	210.49	255.19	J55	59.50	Butt	
119	44.67	5164.18	165.82	210.49	J55	59.50	Butt	
120	41.08	5205.26	124.74	165.82	J55	59.50	Butt	

ADM CCS WELL #1: Intermediate Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
121	44.16	5249.42	80.58	124.74	J55	59.50	Butt	
122	43.99	5293.41	36.59	80.58	J56	59.50	Butt	
123	41.63	5335.04	-5.04	36.59	J57	59.50	Butt	X
124	41.25	5376.29	-46.29	-5.04	J58	59.50	Butt	
125	43.98	5420.27	-90.27	-46.29	J59	59.50	Butt	X
126	41.61	5461.88	-131.88	-90.27	J60	59.50	Butt	
127	43.34	5505.22	-175.22	-131.88	J61	59.50	Butt	
128								
129								
130								
131								
132								
133								
134								
135								
136								
137								
138								
139								
140								
141								
142								
143								
144								
145								
146								
147								
148								
149								
150								

ADM CCS WELL #1: Final Casing Tally

Prepared by: PTH Jr/TG/BH III

Total Depth Tagged (ft.): **7219.47** EST TD

ChromeCasing

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
1	41.74	41.74	7177.73	7219.47	13 Cr 80	47.00	BEAR	
2	19.58	61.32	7158.15	7177.73	13 Cr 80	47.00	BEAR	X
FC	2.50	63.82	7155.65	7158.15	L80	47.00	BEAR	
3	40.09	103.91	7115.56	7155.65	13 Cr 80	47.00	BEAR	X
4	40.13	144.04	7075.43	7115.56	13 Cr 80	47.00	BEAR	X
5	40.05	184.09	7035.38	7075.43	13 Cr 80	47.00	BEAR	X
6	40.15	224.24	6995.23	7035.38	13 Cr 80	47.00	BEAR	X
7	40.16	264.40	6955.07	6995.23	13 Cr 80	47.00	BEAR	X
8	39.55	303.95	6915.52	6955.07	13 Cr 80	47.00	BEAR	X
9	39.77	343.72	6875.75	6915.52	13 Cr 80	47.00	BEAR	X
10	19.09	362.81	6856.66	6875.75	13 Cr 80	47.00	BEAR	X
11	40.18	402.99	6816.48	6856.66	13 Cr 80	47.00	BEAR	X
12	39.49	442.48	6776.99	6816.48	13 Cr 80	47.00	BEAR	X
13	40.04	482.52	6736.95	6776.99	13 Cr 80	47.00	BEAR	X
14	38.91	521.43	6698.04	6736.95	13 Cr 80	47.00	BEAR	X
15	39.36	560.79	6658.68	6698.04	13 Cr 80	47.00	BEAR	X
16	38.87	599.66	6619.81	6658.68	13 Cr 80	47.00	BEAR	X
17	38.52	638.18	6581.29	6619.81	13 Cr 80	47.00	BEAR	X
18	39.60	677.78	6541.69	6581.29	13 Cr 80	47.00	BEAR	
19	39.66	717.44	6502.03	6541.69	13 Cr 80	47.00	BEAR	X
20	40.12	757.56	6461.91	6502.03	13 Cr 80	47.00	BEAR	
21	40.05	797.61	6421.86	6461.91	13 Cr 80	47.00	BEAR	X
22	39.94	837.55	6381.92	6421.86	13 Cr 80	47.00	BEAR	
23	40.03	877.58	6341.89	6381.92	13 Cr 80	47.00	BEAR	X
24	39.85	917.43	6302.04	6341.89	13 Cr 80	47.00	BEAR	
25	40.12	957.55	6261.92	6302.04	13 Cr 80	47.00	BEAR	X
26	38.76	996.31	6223.16	6261.92	13 Cr 80	47.00	BEAR	
27	39.86	1036.17	6183.30	6223.16	13 Cr 80	47.00	BEAR	X
28	40.04	1076.21	6143.26	6183.30	13 Cr 80	47.00	BEAR	
29	40.14	1116.35	6103.12	6143.26	13 Cr 80	47.00	BEAR	X
30	40.02	1156.37	6063.10	6103.12	13 Cr 80	47.00	BEAR	
31	39.63	1196.00	6023.47	6063.10	13 Cr 80	47.00	BEAR	X

ADM CCS WELL #1: Final Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
32	40.09	1235.63	5983.84	6023.47	13 Cr 80	47.00	BEAR	
33	39.90	1275.53	5943.94	5983.84	13 Cr 80	47.00	BEAR	X
34	39.79	1315.32	5904.15	5943.94	13 Cr 80	47.00	BEAR	
35	36.80	1352.12	5867.35	5904.15	13 Cr 80	47.00	BEAR	X
36	38.86	1390.98	5828.49	5867.35	13 Cr 80	47.00	BEAR	
37	40.07	1431.05	5788.42	5828.49	13 Cr 80	47.00	BEAR	X
38	34.92	1465.97	5753.50	5788.42	13 Cr 80	47.00	BEAR	
39	39.95	1505.92	5713.55	5753.50	13 Cr 80	47.00	BEAR	X
40	40.04	1545.96	5673.51	5713.55	13 Cr 80	47.00	BEAR	
41	40.15	1586.11	5633.36	5673.51	13 Cr 80	47.00	BEAR	X
42	39.62	1625.73	5593.74	5633.36	13 Cr 80	47.00	BEAR	
43	39.93	1665.66	5553.81	5593.74	13 Cr 80	47.00	BEAR	X
44	40.08	1705.74	5513.73	5553.81	13 Cr 80	47.00	BEAR	
45	38.45	1744.19	5475.28	5513.73	13 Cr 80	47.00	BEAR	X
46	39.88	1784.07	5435.40	5475.28	13 Cr 80	47.00	BEAR	X
47	39.86	1823.93	5395.54	5435.40	13 Cr 80	47.00	BEAR	X
48	40.05	1863.98	5355.49	5395.54	13 Cr 80	47.00	BEAR	X
49	40.14	1904.12	5315.35	5355.49	13 Cr 80	47.00	BEAR	X
50	40.00	1944.12	5275.35	5315.35	13 Cr 80	47.00	BEAR	
XO	1.50	1945.62	5273.85	5275.35	N80	40.00	LTC	X
51	44.26	1989.88	5229.59	5273.85	N80	40.00	LTC	
52	47.35	2037.23	5182.24	5229.59	N80	40.00	LTC	X
53	46.90	2084.13	5135.34	5182.24	N80	40.00	LTC	
54	46.95	2131.08	5088.39	5135.34	N80	40.00	LTC	X
55	47.55	2178.63	5040.84	5088.39	N80	40.00	LTC	
56	46.82	2225.45	4994.02	5040.84	N80	40.00	LTC	X
57	45.12	2270.57	4948.90	4994.02	N80	40.00	LTC	
58	43.47	2314.04	4905.43	4948.90	N80	40.00	LTC	
59	45.94	2359.98	4859.49	4905.43	N80	40.00	LTC	X
60	46.56	2406.54	4812.93	4859.49	N80	40.00	LTC	

ADM CCS WELL #1: Final Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
61	47.56	2454.10	4765.37	4812.93	N80	40.00	LTC	
62	46.29	2500.39	4719.08	4765.37	N80	40.00	LTC	X
63	46.22	2546.61	4672.86	4719.08	N80	40.00	LTC	
64	45.52	2592.13	4627.34	4672.86	N80	40.00	LTC	
65	46.50	2638.63	4580.84	4627.34	N80	40.00	LTC	X
66	47.55	2686.18	4533.29	4580.84	N80	40.00	LTC	
67	45.12	2731.30	4488.17	4533.29	N80	40.00	LTC	
68	46.01	2777.31	4442.16	4488.17	N80	40.00	LTC	X
69	46.06	2823.37	4396.10	4442.16	N80	40.00	LTC	
70	47.35	2870.72	4348.75	4396.10	N80	40.00	LTC	
71	47.36	2918.08	4301.39	4348.75	N80	40.00	LTC	
72	46.30	2964.38	4255.09	4301.39	N80	40.00	LTC	
73	47.06	3011.44	4208.03	4255.09	N80	40.00	LTC	
74	47.10	3058.54	4160.93	4208.03	N80	40.00	LTC	
75	46.50	3105.04	4114.43	4160.93	N80	40.00	LTC	
76	46.43	3151.47	4068.00	4114.43	N80	40.00	LTC	X
77	45.77	3197.24	4022.23	4068.00	N80	40.00	LTC	
78	47.55	3244.79	3974.68	4022.23	N80	40.00	LTC	
79	46.05	3290.84	3928.63	3974.68	N80	40.00	LTC	
80	43.08	3333.92	3885.55	3928.63	N80	40.00	LTC	
81	46.90	3380.82	3838.65	3885.55	N80	40.00	LTC	
82	47.24	3428.06	3791.41	3838.65	N80	40.00	LTC	
83	45.10	3473.16	3746.31	3791.41	N80	40.00	LTC	
84	47.54	3520.70	3698.77	3746.31	N80	40.00	LTC	
85	47.05	3567.75	3651.72	3698.77	N80	40.00	LTC	
86	46.93	3614.68	3604.79	3651.72	N80	40.00	LTC	
87	47.55	3662.23	3557.24	3604.79	N80	40.00	LTC	X
88	46.65	3708.88	3510.59	3557.24	N80	40.00	LTC	
89	47.34	3756.22	3463.25	3510.59	N80	40.00	LTC	
90	47.43	3803.65	3415.82	3463.25	N80	40.00	LTC	

ADM CCS WELL #1: Final Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
91	47.46	3851.11	3368.36	3415.82	N80	40.00	LTC	
92	46.55	3897.66	3321.81	3368.36	N80	40.00	LTC	
93	47.26	3944.92	3274.55	3321.81	N80	40.00	LTC	
94	47.45	3992.37	3227.10	3274.55	N80	40.00	LTC	
95	47.24	4039.61	3179.86	3227.10	N80	40.00	LTC	
96	46.35	4085.96	3133.51	3179.86	N80	40.00	LTC	
97	47.55	4133.51	3085.96	3133.51	N80	40.00	LTC	X
98	47.33	4180.84	3038.63	3085.96	N80	40.00	LTC	
99	47.36	4228.20	2991.27	3038.63	N80	40.00	LTC	
100	46.29	4274.49	2944.98	2991.27	N80	40.00	LTC	
101	47.24	4321.73	2897.74	2944.98	N80	40.00	LTC	
102	47.38	4369.11	2850.36	2897.74	N80	40.00	LTC	
103	45.35	4414.46	2805.01	2850.36	N80	40.00	LTC	
104	47.35	4461.81	2757.66	2805.01	N80	40.00	LTC	
105	46.63	4508.44	2711.03	2757.66	N80	40.00	LTC	
106	47.53	4555.97	2663.50	2711.03	N80	40.00	LTC	
107	46.70	4602.67	2616.80	2663.50	N80	40.00	LTC	
108	47.25	4649.92	2569.55	2616.80	N80	40.00	LTC	X
109	47.53	4697.45	2522.02	2569.55	N80	40.00	LTC	
110	47.25	4744.70	2474.77	2522.02	N80	40.00	LTC	
111	46.13	4790.83	2428.64	2474.77	N80	40.00	LTC	
112	45.49	4836.32	2383.15	2428.64	N80	40.00	LTC	
113	47.26	4883.58	2335.89	2383.15	N80	40.00	LTC	
114	46.63	4930.21	2289.26	2335.89	N80	40.00	LTC	
115	45.76	4975.97	2243.50	2289.26	N80	40.00	LTC	
116	47.54	5023.51	2195.96	2243.50	N80	40.00	LTC	
117	47.32	5070.83	2148.64	2195.96	N80	40.00	LTC	
118	45.78	5116.61	2102.86	2148.64	N80	40.00	LTC	
119	47.34	5163.95	2055.52	2102.86	N80	40.00	LTC	X
120	45.89	5209.84	2009.63	2055.52	N80	40.00	LTC	

ADM CCS WELL #1: Final Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
121	45.72	5255.56	1963.91	2009.63	N80	40.00	LTC	
122	46.23	5301.79	1917.68	1963.91	N80	40.00	LTC	
123	46.55	5348.34	1871.13	1917.68	N80	40.00	LTC	
124	47.04	5395.38	1824.09	1871.13	N80	40.00	LTC	
125	46.95	5442.33	1777.14	1824.09	N80	40.00	LTC	
126	46.22	5488.55	1730.92	1777.14	N80	40.00	LTC	
127	45.86	5534.41	1685.06	1730.92	N80	40.00	LTC	
128	46.96	5581.37	1638.10	1685.06	N80	40.00	LTC	
129	46.58	5627.95	1591.52	1638.10	N80	40.00	LTC	X
130	47.54	5675.49	1543.98	1591.52	N80	40.00	LTC	
131	47.34	5722.83	1496.64	1543.98	N80	40.00	LTC	
132	46.12	5768.95	1450.52	1496.64	N80	40.00	LTC	
133	47.35	5816.30	1403.17	1450.52	N80	40.00	LTC	
134	46.37	5862.67	1356.80	1403.17	N80	40.00	LTC	
135	45.06	5907.73	1311.74	1356.80	N80	40.00	LTC	
136	47.26	5954.99	1264.48	1311.74	N80	40.00	LTC	
137	47.28	6002.27	1217.20	1264.48	N80	40.00	LTC	
138	47.55	6049.82	1169.65	1217.20	N80	40.00	LTC	
139	46.65	6096.47	1123.00	1169.65	N80	40.00	LTC	
140	45.34	6141.81	1077.66	1123.00	N80	40.00	LTC	
141	47.34	6189.15	1030.32	1077.66	N80	40.00	LTC	X
142	45.84	6234.99	984.48	1030.32	N80	40.00	LTC	
143	47.54	6282.53	936.94	984.48	N80	40.00	LTC	
144	46.86	6329.39	890.08	936.94	N80	40.00	LTC	
145	46.50	6375.89	843.58	890.08	N80	40.00	LTC	
146	44.99	6420.88	798.59	843.58	N80	40.00	LTC	
147	45.95	6466.83	752.64	798.59	N80	40.00	LTC	
148	47.55	6514.38	705.09	752.64	N80	40.00	LTC	
149	47.47	6561.85	657.62	705.09	N80	40.00	LTC	
150	47.03	6608.88	610.59	657.62	N80	40.00	LTC	

ADM CCS WELL #1: Final Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
151	47.25	6656.13	563.34	610.59	N80	40.00	LTC	X
152	47.37	6703.50	515.97	563.34	N80	40.00	LTC	
153	46.62	6750.12	469.35	515.97	N80	40.00	LTC	
154	47.54	6797.66	421.81	469.35	N80	40.00	LTC	
155	47.32	6844.98	374.49	421.81	N80	40.00	LTC	
156	47.33	6892.31	327.16	374.49	N80	40.00	LTC	
157	46.53	6938.84	280.63	327.16	N80	40.00	LTC	
158	43.42	6982.26	237.21	280.63	N80	40.00	LTC	X
159	47.54	7029.80	189.67	237.21	N80	40.00	LTC	
160	47.54	7077.34	142.13	189.67	N80	40.00	LTC	
161	47.53	7124.87	94.60	142.13	N80	40.00	LTC	
162	47.35	7172.22	47.25	94.60	N80	40.00	LTC	
163	47.25	7219.47	0.00	47.25	N80	40.00	LTC	
164	47.12	7266.59	-47.12	0.00	N80	40.00	LTC	
165	47.55	7314.14	-94.67	-47.12	N80	40.00	LTC	
166	46.33	7360.47	-141.00	-94.67	N80	40.00	LTC	
167	45.47	7405.94	-186.47	-141.00	N80	40.00	LTC	
168	46.93	7452.87	-233.40	-186.47	N80	40.00	LTC	
169	47.38	7500.25	-280.78	-233.40	N80	40.00	LTC	
170	47.53	7547.78	-328.31	-280.78	N80	40.00	LTC	
171	47.34	7595.12	-375.65	-328.31	N80	40.00	LTC	
172								
173								
174								
175								
176								
177								
178								
179								
180								

Appendix XIII.A – Revised Form 4a

4 UIC Form 4a, Hydrogeologic Information

Last revised: 4/29/2010 (note: EM added page numbers to this section).

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT APPLICATION

FORM 4a - HYDROGEOLOGIC INFORMATION

USEPA I.D. NUMBER ILD984791459
IEPA I.D. NUMBER 1150155136
UIC Well Number CCS #1

I Elevation of Land Surface at Well Location

The surface elevation at the CCS#1 well is 674.22 feet above mean seal level (MSL). During well drilling, the reference elevation was the rig's kelly bushing, which had an elevation of 689.85 feet above MSL.

II Faults, known or suspected within the area of review

No regional faults that are known to cross the area of review. Analysis of the current seismic reflection data showed no observable faults. The CCS#1 did not penetrate any known faults. As discussed in the Feasibility Report, the original 2D seismic reflection data acquired before the well was drilled suggested that possible fractured intervals may be found in the Mt. Simon. A review of the original seismic reflection data suggests that these fractured zones may be artifacts of poor quality data. Noise from the nearby ADM industrial plant and the Caterpillar plant on the west side of the study area reduces the quality of the seismic data and limits our ability to draw firm conclusions from the seismic data.

III Maps and cross sections as required by Section 730.114(a) or 730.134(a)

Maps and cross-sections perpendicular to each other at the ADM injection site were shown in Figures 20-22 of the Feasibility Report. The cross-sections included available log control, geologic units, and lithology from the surface to the lower confining bed below the injection zone. The closest Mt. Simon well to the Decatur area (17 miles southeast of CCS#1) is the Sanders #7. The Sanders #7 only drilled the uppermost 200 feet of the Mt. Simon and did not penetrate the deeper reservoir zone. Unfortunately, there were no deep wells that penetrated the Knox, Ironton-Galesville, Eau Claire (the primary seal), or Mt. Simon Sandstone within a 17 mile radius of the proposed injection site. All of the deeper horizons are projected from regional mapping.

The closest wells that penetrate the injection horizon are 51 miles (Weaber-Horn #1) and 37 miles (Hinton#7) from the CCS#1 well. The Weaber-Horn #1 well had an average Mt. Simon reservoir porosity of about 12 percent, as calculated from wireline logs. The Weaber-Horn #1 well porosity data are similar to those found in the Hinton #7 at the Manlove Gas Storage Field in Champaign County. The Manlove Field is the deepest Mt. Simon gas storage field in the Illinois Basin and provides one of the best sets of reservoir data for characterization of the deep Mt. Simon. As expected the porosity values at the CCS#1 well are similar to those found at the Weaber-Horn #1 well and the Manlove Gas Storage Field. A north-south trending cross section (see A-A' in Figure CCS1_hinton_xsd_Mehnert.pdf, Figure 4a1) across the Hinton #7, CCS#1, Harrison #1, and Weaber-Horn #1 wells shows that the Mt. Simon at the CCS#1 well has the same lower porous and permeable interval.

IV Injection Zone

Regional

The thickest and most widespread saline water bearing reservoir (saline reservoir) in the Illinois Basin is the Cambrian-age Mt. Simon Sandstone (Figure 4a2). CO₂ injected through CCS#1 will be contained in the injection zone. The initial injection interval is a portion of the Mt. Simon where the injection well is perforated, between depths of 6,982 to 7,050 feet.

It is overlain by the Cambrian Eau Claire Formation, a regionally extensive very low-permeability shale, and underlain by the Precambrian granitic basement.

The regional properties and thickness of the Mt. Simon were discussed in the Feasibility Report.

A. Geologic name(s) of injection zone.

The injection zone is the Cambrian-age Mt. Simon Sandstone (Figure 4a2). CO₂ injected through CCS#1 will be contained in the injection zone and will flow into the Mt. Simon at the injection interval. The injection interval is a portion of the Mt. Simon where the injection well is perforated.

B. Depth interval of injection zone beneath land surface

At the ADM site, the Mt. Simon was found at a depth of 5,545 feet to 7,051 feet based on borehole logging data. An interval of high porosity and permeability was identified at the base of the Mt. Simon. This interval was selected as the initial injection interval and was perforated from 6,982 to 7,050 ft.

C. Characteristics of injection zone.

The injection zone is a porous and permeable sandstone that, in some intervals, is an arkose. Grain size varies from very-fine grained to coarse grained. The sandstones are primarily composed of quartz, but some sandstone intervals can contain more than 15 percent feldspar. Diagenetic clay minerals are not common.

2. Injection zone thickness available to accept waste.

While CO₂ may be stored in the entire thickness of the Mt. Simon, CO₂ will be initially injected at the perforated or injection interval at the base of the Mt. Simon. CCS#1 is perforated at a depth of 6,982 to 7,050 feet.

3. Fracture pressure at top of injection interval

A step-rate test was conducted on September 26, 2009 into the initial 25 foot perforated interval from 7,025 to 7,050 feet at the base of the Mt. Simon (Earlougher, 1977). The primary purpose of the test was to estimate the fracture pressure of the injection interval. A bottom-hole pressure gauge with surface readout was used. The pressure gauge was located at 6,891 feet inside the tubing, 134 feet above the upper-most perforation.

Water with clay stabilizing potassium chloride was injected in 2.0 barrel per minute (bpm) increments starting at 2.0 bpm (84 gallons per min, gpm) to 8.0 bpm (336 gpm). Each rate was

maintained for approximately 45 minutes. The pressure near the end of each injection period was plotted against the injection rate in Figure 4a3 to determine the fracture pressure.

The first line with the greater slope at lower rates and pressure is the perforated interval's response to water injection prior to fracturing. The second line with the lower slope at higher rates and pressures is after the fracture developed. The intersection of the two straight lines is 4,966 psig. To find the fracture pressure at the top of the perforations, the hydrostatic pressure of the water in the wellbore between 6,891 (location of pressure gauge) and 7,025 feet was added to the 4,966 psig. The fracture pressure at 7,025 feet is 5,024 psig.

Source:

Earlougher, Jr., R.C., 1977. *Advances in Well Test Analysis*, Monograph Series, Society of Petroleum Engineers of AIME, Dallas, 5.

4. Effective porosity, include source

The compensated neutron and litho-density open-hole, porosity logs run were run in CCS#1. The neutron and density logs provide total porosity data. Effective porosity was determined by lab testing using the helium porosimeter method on a limited number of core plug samples. See Section X for additional discussion about the helium porosimeter method.

A comparison was made between the neutron-density crossplot porosity (average neutron and density porosity) and core porosity (Figure 4a4). These porosity sources compared well. Consequently, the neutron-density crossplot porosity was used to estimate effective porosity.

Based on porosity trends, there are 7 major sub-intervals present in the Mt. Simon. Table 4a1 lists the intervals identified and the average effective porosity of each. Based on the neutron-density crossplot porosity, the 68-foot, injection interval (6,982-7,050 feet) has an average effective porosity of 21.0%.

Table 4a1: Average effective porosity based on the neutron-density crossplot porosity. The seven sub-intervals were selected based on major changes in the trend of porosity from the neutron-density logs.

Sub-Interval (feet)	Effective Porosity (%)
5,545-5,900	10.8
5,900-6,150	8.72
6,150-6,430	10.1
6,430-6,650	15.2
6,650-6,820	21.8
6,820-7,050	18.7
7,050-7,165	9.84

5. Intrinsic permeability, include source

Intrinsic permeability was directly available from core analyses and well testing. However, to estimate permeability over a larger interval where core is not available, a relationship between core permeability and log porosity is required.

Core Analysis

A core porosity-permeability transform was developed (Figure 4a5) based on grain size. A neutron-density crossplot porosity was used with this transform to estimate permeability with depth. Average permeability for sub-intervals of the Mt. Simon for CCS#1 is in Table 4a2. Based on the neutron-density crossplot porosity and the core porosity-permeability transform, the 68-foot, injection (perforated) interval (6,982-7,050 feet) has an average intrinsic permeability of 194 md.

Well Testing

Three pressure falloff (PFO) tests of varying duration were conducted in September and October 2009 as part of the initial completion of CCS#1. A pressure falloff test involves two segments. During the first test segment, the reservoir is stressed by injecting fluid, which changes the reservoir pressure. During the second test segment, the reservoir pressure is monitored as it returns to its pre-test pressure. An analogous test in the groundwater industry is a recovery test where water is pumped instead of injected during the first test segment.

The initial perforations in the injection interval were 7,025 to 7,050 feet. Water treated with a clay-stabilizing potassium chloride substitute was injected at 1.5 to 2.0 barrels per minute (bpm) (63 to 84 gallons per minute) for nearly two hours. A 19.5 hour PFO followed this injection period.

After this test, these perforations were acidized and a step-rate test was conducted. For the second step-rate test, treated water was injected at 3.1 bpm (130 gpm) for five hours, while pressure was monitored for approximately 45 hours.

The third PFO test was conducted after the well was perforated and stimulated. An additional 30 feet of perforations were added at 6,982 to 7,012 feet. The perforated zone received a second acid treatment. Additional information regarding perforations and acid treatment are described in Completion Report Form 4h, Section X.E. For the third PFO test, the treated water was injected at an increasing rate of 3.1 to 4.2 bpm (130 to 176 gpm) over 6.5 hours and then at 4.2 bpm (176 gpm) for an additional 6.5 hours. During this third PFO test, pressure was monitored for 105 hours.

Pressure Transient Analyses

PIE pressure transient software (Well-Test Solutions, Ltd., <http://welltestsolutions.com/index.html>) was used to analyze the pressure data for reservoir flow properties. Conventional semilog, log-log and nonlinear regression analyses were used to analyze the data.

During the first PFO, because only 25 feet of perforations were open in a very large vertical formation (gross thickness 1,506 feet), a partial penetration or partial completion effect was expected. The derivative (log-log plot) of the falloff test is used to qualitatively identify reservoir features including the partial penetration effect (Figure 4a6) and to determine permeability. Two radial, 2-dimensional responses (horizontal derivative) were measured during this test between 0.1 and 1 hrs (PPNSTB) and 20 to 100 hrs (STABIL). The first period corresponds to radial flow across the 25 ft perforated interval; the second period corresponds to the pressure response across a

larger thickness that would be between two much lower permeability sub-units. The transition between the two radial responses (SPHERE) is a spherical flow (3-dimensional flow) period that is influenced by vertical permeability (or k_v/k_h , the ratio of vertical to horizontal permeability).

To observe the effect of the acid treatment and the second set of perforations to the overall injection interval, the derivatives of the three pressure falloff tests were overlain (Figure 4a7). The data between 0.1 and 1.0 hrs match relatively well and the data between 1.0 and 100 hrs match very well. Similar trends of the first radial period, transition and final radial period indicates that the second set of perforations did not change the permeability estimated from the pressure transient tests or contribute to the perforated interval. As such the subsequent pressure transient analyses used a single layer, partial penetration model with 25 ft of perforations open at the base of the layer.

Simulation of the pressure transient data using analytical solutions (Figure 4a8), gave a permeability of 185 md over 75 ft of vertical thickness. The transition period gave a vertical permeability over the 75 ft as 2.45 md ($k_v/k_h = 0.01326$).

The Mt. Simon initial pressure at CCS#1 at 7,025 ft is about 3,200 psig.

The average Mt. Simon permeability for all of the cored Mt. Simon Sandstone was 29.7 md for the Manlove Field. These permeability values includes both reservoir and non-reservoir facies. The average permeability of the porous and permeable intervals of the Manlove Field is expected to be several hundred millidarcy. The permeability in the lower interval (injection interval of interest) had a sidewall core plug in the Hinton #7 well with permeability in excess of 1,000 md. Thus, the estimated mean permeability for CCS #1 is similar to other estimates of Mt. Simon in the Illinois Basin.

For the injection interval, the permeability estimates from three methods are very close. Based on the neutron-density crossplot porosity and the core porosity-permeability transform, the 68-foot, injection (perforated) interval (6,982 to 7,050 feet) has an average intrinsic permeability of 194 md. Using the PIE pressure transient software for the third PFO, permeability was estimated to be 185 md over 75 ft of vertical thickness. Permeability for this same 75 feet of rock was calculated using core and well log analyses. The permeability from this analysis was estimated to be 182 md.

Table 4a2: Average intrinsic permeability based on a transform of core permeability and core porosity related to the neutron-density crossplot porosity for the sub-intervals shown. The seven sub-intervals were selected based on major changes in the trend of porosity from the neutron-density logs.

Sub-Interval (feet)	Intrinsic Permeability (md)
5,545-5,900	19.4
5,900-6,150	10.2
6,150-6,430	8.44
6,430-6,650	8.21
6,650-6,820	8.64
6,820-7,050	107
7,050-7,165	4.37

6. Hydraulic conductivity or permeability, include source

Intrinsic permeability (k) and hydraulic conductivity (K) are related according to the following equation (Freeze and Cherry, 1979):

$$K = k \rho g / \mu$$

where ρ = fluid density

g = gravitational acceleration

μ = dynamic viscosity

Intrinsic permeability (k) is a property of the rock, while hydraulic conductivity (K) includes properties of the rock and fluid. Intrinsic permeability is also known as permeability and is discussed in Section IV.C.5. Formation water density and dynamic viscosity are discussed in Sections IV.D.3 and IV.D.4, respectively. For the range of viscosity and density discussed, the hydraulic conductivity will vary.

The injection interval (6,982 to 7,050 feet) had an average intrinsic permeability of 194 md, this converts to a hydraulic conductivity of 3.9×10^{-6} m/sec, using the fluid properties at this depth.

Source:

Freeze, R. A. and J. A. Cherry, 1979. *Groundwater*. Englewood Cliffs, N.J., Prentice-Hall, Inc.

7. Storage coefficient, include source

The storage coefficient or storativity, S, ranges from 5×10^{-5} to 5×10^{-3} for confined aquifers (Freeze and Cherry, 1979). S is commonly determined by well testing; however, S is a function of fluid compressibility (c_f) and rock compressibility (c_r) and can be estimated from the following equation:

$$S = \rho g h (c_r + \phi c_f)$$

where ϕ = porosity

h = formation thickness

ρ = fluid density

g = gravitational acceleration

Rock compressibility can be expressed as the inverse of the bulk modulus (K_b) and in terms of the Young's modulus (E) and Poisson's ratio (ν) (Huang and Rudnicki, 2006):

$$c_r = 1/K_b = 3(1 - 2\nu)/E$$

Fluid density is discussed in Section IV.D.3. Gravitational acceleration equals 9.81 m/sec^2 . For this calculation, the Mt. Simon is assumed to be 1,506 feet thick and have 10% porosity (Φ). Young's modulus (E) and Poisson's ratio (ν) were determined by Weatherford Laboratory (see Section X for more

details) for Mt. Simon samples collected at depths of 6,761 and 6,770 feet. These values were used to compute c_r using the equation shown above. These compressibility values are consistent with bulk compressibility values for sandstone reservoirs, which ranged from 6.5×10^{-5} to 2.7×10^{-4} MPa⁻¹ at 7,000 psi (48.3 MPa) confining pressure (Zimmerman, 1991). Fluid compressibility (c_f) are known to vary with pressure and temperature changes (Huang and Rudnicki, 2006). Using two samples collected from CCS#1 (MDT-1 & MDT-4), fluid compressibility and storativity values were estimated (Table 4a4).

Based on the range of values described here, storativity was estimated to range from 8.1×10^{-5} to 9.3×10^{-4} (Table 4a3). These values are consistent with values published by Freeze and Cherry (1979).

Table 4a3. Estimates of rock (c_r) and fluid (c_f) compressibility and storativity (S)

depth (ft)	pressure (psi)	pressure (MPa)	T (°C)	ρ (g/L)	c_r (1/Mpa)	c_f (1/Mpa)	Φ (-)	h (m)	S (-)
5772	2582.9	1.78E+01	48.8	1089.7	2.02E-04	2.04E-04	0.10	459.0	8.91E-04
7045	3206.1	2.21E+01	52.1	1123.5	2.02E-04	1.83E-04	0.10	459.0	9.29E-04
5772	2582.9	1.78E+01	48.8	1089.7	3.68E-05	2.04E-04	0.10	459.0	8.07E-05
7045	3206.1	2.21E+01	52.1	1123.5	3.68E-05	1.83E-04	0.10	459.0	9.35E-05

Source:

Huang, T. and J.W. Rudnicki, 2006. A mathematical model for seepage of deeply buried groundwater under higher pressure and temperature. *Journal of Hydrology* 327(1-2): 42-54.

Freeze, R.A. and J.A. Cherry, 1979. *Groundwater*. Englewood Cliffs, N.J., Prentice-Hall, Inc.

Zimmerman, R.W., 1991. *Compressibility of Sandstones*. Amsterdam, Elsevier.

8. Seepage velocity (ft/yr) and flow direction of formation water, include source.

Groundwater flow in the deeper part of the Illinois Basin was discussed in the Feasibility Report and included model projections of groundwater flow in the Mt. Simon by Gupta and Bair (1997). The location of the CCS#1 was plotted on the potentiometric surface map developed by Gupta and Bair (1997). The potentiometric surface was estimated to be 76 m (250 ft) in Section IV.D.6, which is slightly higher than the projected estimate of 25 to 50 m from Figure 4a9 (gupta&bair_1997_revisedkorose.jpg).

References

Gupta, N., and E.S. Bair, 1997. Variable-density flow in the midcontinent basins and arches region of the United States. *Water Resources Research*, 33(8): 1785-1802.

D. Characteristics of injection zone formation water

Fluid samples were collected from the CCS#1 open borehole, after drilling and wireline geophysical testing were completed. Schlumberger's Modular Formation Dynamics Tester (MDT) and

Quiksilver wireline equipment were run on April 28 and 29, 2009. The tool was used to collect formation pressure, formation temperature, and high-quality reservoir fluid samples at five depths (Table 4a4). Prior to collecting a reservoir sample, the MDT measures the fluid resistivity to help discriminate between formation fluids and drilling mud filtrate. Fluid sample volume varied from 450 mL to 900 mL. These samples were analyzed by the Illinois State Water Survey.

Table 4a4. Data for fluid samples collected from the Mt. Simon sandstone using the MDT sampler in April 2009

Sample ID	Sample Depth (feet)	Formation Pressure (psi)	Formation Temperature (°F)	TDS (mg/L)	Density (g/L)
MDT-4	5,772	2,582.9	119.8	164,500	1,089.7
MDT-3	6,764	3,077.5	125.1	185,600	1,120.7
MDT-14	6,764	3,077.5	125.1	179,800	NA
MDT-5	6,840	3,105.9	125.0	182,300	1,124.1
MDT-2	6,912	3,141.8	125.8	211,700	1,136.5
MDT-9	6,840	3,105.9	125.0	219,800	NA
MDT-1	7,045	3,206.1	125.7	228,100	1,123.5
MDT-8	7,045	3,206.1	125.7	201,500	NA

NA= not analyzed

1. Temperature, include source

Based on the MDT sampler (Table 4a4), formation temperatures ranged from 119.8°F (48.8 °C) at a depth of 5,772 feet to 125.8°F (52.1°C) at depth of 6,912 feet.

2. Pressure, include source

Assuming a pressure gradient of 0.433 psi/feet, the pressure at the top of the Mt. Simon was estimated to be between 2,165 to 2,598 psi for estimated depths of 5,000 to 6,000 feet. The formation pressure measured with the MDT tool also varied with depth and had a minimum pressure of 2,583 psi recorded at 5,772 feet and a maximum pressure of 3,206 psi recorded at 7,045 feet.

3. Density, include source

Based on five samples collected with the MDT sampler, the fluid density ranged from 1,090 to 1,137 g/L, with an average of 1,119 g/L.

4. Viscosity, include source

Dynamic viscosity is a function of brine temperature, salinity, and formation pressure. Viscosity increases with higher salinity and with lower temperatures. Viscosity slightly increases with higher formation pressure (Kestin et al., 1981). Kestin et al. (1981) studied the viscosity of NaCl brines. Because the Mt. Simon brine is predominantly an NaCl brine, using the method of Kestin et al. (1981) is appropriate.

Using the data in Table 4a4, the brine viscosity for the Mt. Simon brine is estimated to range from 5.4×10^{-4} to 5.7×10^{-4} Pa sec with an average of 5.5×10^{-4} Pa sec.

Source:

Kestin, J., E. Khalifa and R.J. Correia, 1981. Tables of dynamic and kinematic viscosity of aqueous NaCl solutions in the temperature range 20-150°C and the pressure range 0.1-35MPa., *Journal of Physical and Chemical Reference Data*, 10(1): 71-87.

5. Total Dissolved Solids, include source

Salinity, expressed as TDS, also affects the injection capacity because it reduces the CO₂ solubility in water. Figure 17 in the Feasibility report showed the broad distribution of TDS in the Mt. Simon which should exceed 60,000 mg/L over much of the Illinois Basin and 180,000 mg/L in the deeper portions of the basin (Leetaru et al., 2005).

At the ADM site, the Mt. Simon brine was expected to be 100,000 to 140,000 mg/L TDS. Samples collected from the injection well varied with depth (Table 4a4), with TDS of 164,500 mg/L TDS at 5,772 feet and 228,100 mg/L TDS at 7,045 feet. The average TDS for the eight samples is 196,700 mg/L.

Source:

Leetaru, H., E. Mehnert, S. Rittenhouse, J. Drahovzal, S. Fisher, and J. McBride, 2005. Saline reservoirs as a sequestration target, in An Assessment of Geological Carbon Sequestration Options in the Illinois Basin, Final Report for U.S. DOE Contract: DE-FC26-03NT41994, Principal Investigator: Robert Finley, p 253-324.

6. Potentiometric surface, include source

Little information is available about the potentiometric surface in the Mt. Simon sandstone in Macon County because very few wells penetrate the Mt. Simon in central Illinois. The best available information regarding the potentiometric surface is discussed in Section IV.C.8 of this form.

Using the formation pressure (p) and fluid density (ρ) data in Table 4a4, the potentiometric head (h) was calculated using the relationship— $p = \rho gh$, where g is the gravitational constant. The mean potentiometric head in the Mt. Simon has an elevation 249.5 feet above mean sea level. If the well were filled with freshwater (ρ= 1,000 g/L), the potentiometric head would have an elevation of 996.1 feet.

E. Additional or alternative zones considered for injection

No other geologic zones are being considered for injection at the ADM site.

V. Upper Confining Zone

A. Geologic name(s) of confining zone

The primary confining zone (seal) is the Cambrian-age Eau Claire Formation (Figure 4a2). An isopach map based on regional well control suggests that the Eau Claire should be 300 to 500 feet thick at the

ADM site. Based on the data from CCS#1, the Eau Claire has a total thickness of 497.5 feet. The shale section of the Eau Claire has a thickness of 198.1 feet and is the lowermost section within the Eau Claire.

B. Depth interval of upper confining zone beneath land surface.

The Eau Claire Formation occurs at a depth of 5,047 feet to 5,545 feet below ground surface. The shale section of the Eau Claire occurs at a depth of 5,347 to 5,545 feet.

C. Characteristics of confining zone

1. Lithologic description

In the central part of the Illinois Basin, the Cambrian age Eau Claire Formation is a mixture of carbonates and fine-grained siliciclastics. At CCS#1, the upper section of the Eau Claire (5,047 to 5,347 feet) was dense limestone with thin stringers of siltstone. The lower section of the Eau Claire (5,347 to 5,545 feet) was a shale. As discussed in the Feasibility Report, the Eau Claire shale interval above the Mt. Simon is persistent in the Illinois Basin and is expected to provide a good seal for the injection zone.

From limited x-ray diffraction data, the mineralogy of the shale is 60 percent clay minerals and 37 percent quartz and potassium feldspar. The shale is thinly laminated and dark gray to black in color.

2. Fracture pressure at depth, include source

A mini-frac test using Schlumberger's Modular Dynamics Testing tool was conducted across a 2.8-foot interval centered at a depth of 5,435 feet. Thus, this mini-frac test was conducted on the shale section of the Eau Claire formation. The test was designed for four, short-term injection/falloff test periods (15 to 60 minutes in duration). The fracture pressure from these four tests ranged from 5,078 to 5,324 psig, corresponding to a fracture gradient ranging from 0.93 to 0.98 psi/ft in the Eau Claire Shale.

3. Intrinsic permeability, include source

None of the sidewall rotary core plugs are described as shale. From the whole core, taken within the Eau Claire, no part of the shale was large enough for drilling a core plug and subsequent analyses. The sidewall rotary core plugs are taken horizontally, so permeability from these plugs is horizontal (not vertical) permeability which is less relevant for a confining layer.

The plugs are described as very fine grained sandstones, microcrystalline limestone and siltstone. Within the upper confining interval of 5,047 to 5,545 feet, 12 plugs were available for porosity and permeability testing. Because vertical flow is of most interest for the upper confining layer, the average vertical permeability over the confining layer was estimated. The average vertical permeability using the horizontal permeability from the 12 sidewall rotary core plugs is 0.000344 md.

The average vertical permeability over the upper confining layer is expected to be much lower than 0.000344 md because this average is based on horizontal permeability values and no shale permeability was included. Vertical permeability on plugs is generally lower than horizontal permeability and shale permeability is generally much lower than sandstone, limestone, and siltstone.

4. Hydraulic conductivity, include source

Intrinsic permeability (k) and hydraulic conductivity (K) are related according to the following equation (Freeze and Cherry, 1979):

$$K = k \rho g / \mu$$

where ρ = fluid density

g = gravitational acceleration

μ = dynamic viscosity

Intrinsic permeability (k) is a property of the rock, while hydraulic conductivity (K) includes properties of the rock and fluid. Intrinsic permeability is also known as permeability and is discussed in Section IV.C.5. Fluid density is discussed in Section IV.D.3, while dynamic viscosity is discussed in Section IV.D.4. No fluid samples were collected from the Eau Claire. For these calculations, the fluid properties of sample MDT-4 (Table 4a4) were used. This Mt. Simon brine sample was collected closest to the Eau Claire. Its measured properties include temperature of 119.8°F and density of 1,089.7 g/L. Its dynamic viscosity was estimated to be 758.0 microPa sec. For an intrinsic permeability values of 0.000344 md, the hydraulic conductivity equals 4.8×10^{-12} m/sec.

Sources:

Freeze, R. A. and J. A. Cherry, 1979. *Groundwater*. Englewood Cliffs, N.J., Prentice-Hall, Inc.

5. Alternative confining zones proposed, include explanation and depth interval(s)

Secondary seals provide additional backup containment of the CO₂ should an unlikely failure of the primary seal occur. Secondary seals listed here are units with low permeability that are regionally present and serve as cap rocks for oil, gas and gas storage fields throughout Illinois where they are present.

Two secondary seals were found at the ADM site. The Ordovician-age Maquoketa Shale (Figure 4a2) is laterally continuous across the ADM site and is 206 feet thick at the ADM site at a depth of 2,611 feet below ground. This shale is a regional seal for production from the Ordovician Galena (Trenton) Limestone. The Devonian-Mississippian-age New Albany Shale at a depth of 2,088 feet is about 126 feet thick at the ADM study area. Extensive well control from oil fields shows that this shale is a good seal for hydrocarbons; hence, it should also be a good secondary seal against the vertical migration of CO₂.

VI. Lower Confining Zone

Because the lower confining zone is the basement granite and no other sedimentary rocks are below the granite, no data were collected on the granite. The fracture pressure, porosity and permeability of the granite will not impact injection or fluid migration as the CO₂ injection interval will be above this confining zone and the CO₂ is expected to move upward away from the granite.

A. Geologic name(s) of confining zone

The lower confining zone is the Precambrian granite basement.

B. Depth interval of lower confining zone beneath land surface

The top of the Precambrian basement rock was found at a depth of 7,165 feet below ground surface.

C. Characteristics of confining zone

1. Lithologic description

The Precambrian-age rock in the Illinois Basin is composed of a medium- to coarse-grained granite or rhyolite and is between 1.1 to 1.4 billion years old (Bickford et al., 1986). At the CCS#1 well, we encountered the Precambrian granite/rhyolite at a measured depth of 7,165 feet.

Source:

Bickford, M.E., W.R. Van Schmus, and I. Zietz, 1986. Proterozoic history of the midcontinent region of North America: *Geology*, (14) 6, 492–496.

2. Fracture pressure at depth, include source

The Illinois State Geological Survey could not find any data on fracture pressure of granites in Illinois nor did we conduct any tests to determine the fracture pressure of the lower confining zone. The fracture pressure of the granite is not anticipated to have any effect on the injection or storage of CO₂ in the Mt. Simon.

3. Intrinsic permeability, include source

The top of the granite occurs at depth of 7,165 feet. A total of 65 feet of granite was drilled. At 7,200 feet, one core plug was collected; the permeability was 0.0091 mD.

4. Hydraulic conductivity, include source

Using the pressure and fluid properties obtained for MDT-1 (Table 4a4), hydraulic conductivity for the granite is estimated to be 1.8×10^{-10} m/sec.

5. Alternative confining zones proposed, include explanation and depth interval(s)

There are no alternative lower confining zones since no wells in Illinois have found anything else but the Precambrian granite basement below the Mt. Simon Sandstone.

VII. Overlying Sources of Groundwater at the Site

Overlying sources of groundwater which meet the definition of underground sources of drinking water (USDW) include three units from shallowest to deepest—Quaternary sand and gravel, Pennsylvanian

bedrock, and the St. Peter Sandstone. Field investigations to determine the lowermost USDW at this site were discussed in a letter from Dean Frommelt of ADM to Illinois EPA, dated September 29, 2009.

Summarizing the information in this letter, water sampling showed that the water in the St. Peter Sandstone had a total dissolved solids (TDS) concentration of 4,540 mg/L, which is below the USDW limit of 10,000 mg/L TDS. In addition, the water quality in the Pennsylvanian bedrock transitions from fresh water (TDS < 10,000 mg/L) to brine (TDS > 10,000 mg/L) with depth. Currently, groundwater in the Pennsylvanian bedrock below 275 feet is considered brine. Additional monitoring wells will be installed in 2010 to help establish the boundary between the fresh water and brine in the Pennsylvanian bedrock.

Source:

Frommelt, D. 2009. Letter to Illinois Environmental Protection Agency, Subject: Lowermost underground source of drinking water (USDW), Archer Daniels Midland Company—UIC Permit UIC-012-ADM, dated September 29, 2009.

A. Characteristics of the aquifer immediately overlying the confining zone

1. Elevation at top of aquifer, include source

The first aquifer which contains salt water at the proposed location overlying the Eau Claire Formation (the primary seal for the Mt. Simon Sandstone) is the Ironton-Galesville Formation (Figure 4a2). Based on the geophysical logging in CCS#1, the Ironton-Galesville was found at depths of 4,928 to 5,047 feet (119 feet thick).

2. Potentiometric surface, include source

No potentiometric data were collected during drilling of CCS#1 for the Ironton-Galesville. Thus, this section can not be updated from the Feasibility Report.

3. Total Dissolved Solids, include source

No water quality data were collected during drilling of CCS#1 for the Ironton-Galesville. Thus, this section can not be updated from the Feasibility Report.

4. Lithology, include source

No lithologic data were collected during drilling of CCS#1 for the Ironton-Galesville. Thus, this section can not be updated from the Feasibility Report.

5. Aquifer thickness

Based on the geophysical logging in CCS#1, the Ironton-Galesville was found to be 119 feet thick.

6. Specific gravity, include source

No water quality data were collected during drilling of CCS#1 for the Ironton-Galesville. Thus, this section can not be updated from the Feasibility Report.

B. Underground Sources of Drinking Water (USDW)

1. Maps and cross sections required by 730.114(a)(4) or 730.134(a)(4)

See the Feasibility Report for current maps and cross-sections of USDW. However, significant new data regarding the lowermost USDW was presented in a letter from Dean Frommelt of ADM to Illinois EPA, dated September 29, 2009.

2. Lowest depth of USDW

Overlying sources of groundwater which meet the definition of underground sources of drinking water (USDW) include three units from shallowest to deepest—Quaternary sand and gravel, Pennsylvanian bedrock, and the St. Peter Sandstone. Field investigations to determine the lowermost USDW at this site were discussed in a letter from Dean Frommelt of ADM to Illinois EPA, dated September 29, 2009.

Summarizing the information in this letter, water sampling showed that the water in the St. Peter Sandstone had a total dissolved solids (TDS) concentration of 4,540 mg/L, which is below the USDW limit of 10,000 mg/L TDS. In addition, the water quality in the Pennsylvanian bedrock transitions from fresh water (TDS < 10,000 mg/L) to brine (TDS > 10,000 mg/L) with depth. Currently, groundwater in the Pennsylvanian bedrock below 275 feet is considered to be a brine. Additional monitoring wells will be installed in 2010 to help refine the boundary between the fresh water and brine in the Pennsylvanian bedrock.

3. Elevation of potentiometric surface of lowest USDW referenced to mean sea level

See the Feasibility Report for a discussion regarding the potentiometric surface of the lowermost USDW.

4. Distance to nearest water supply well

See the Feasibility Report for a discussion regarding data on the nearest water supply well.

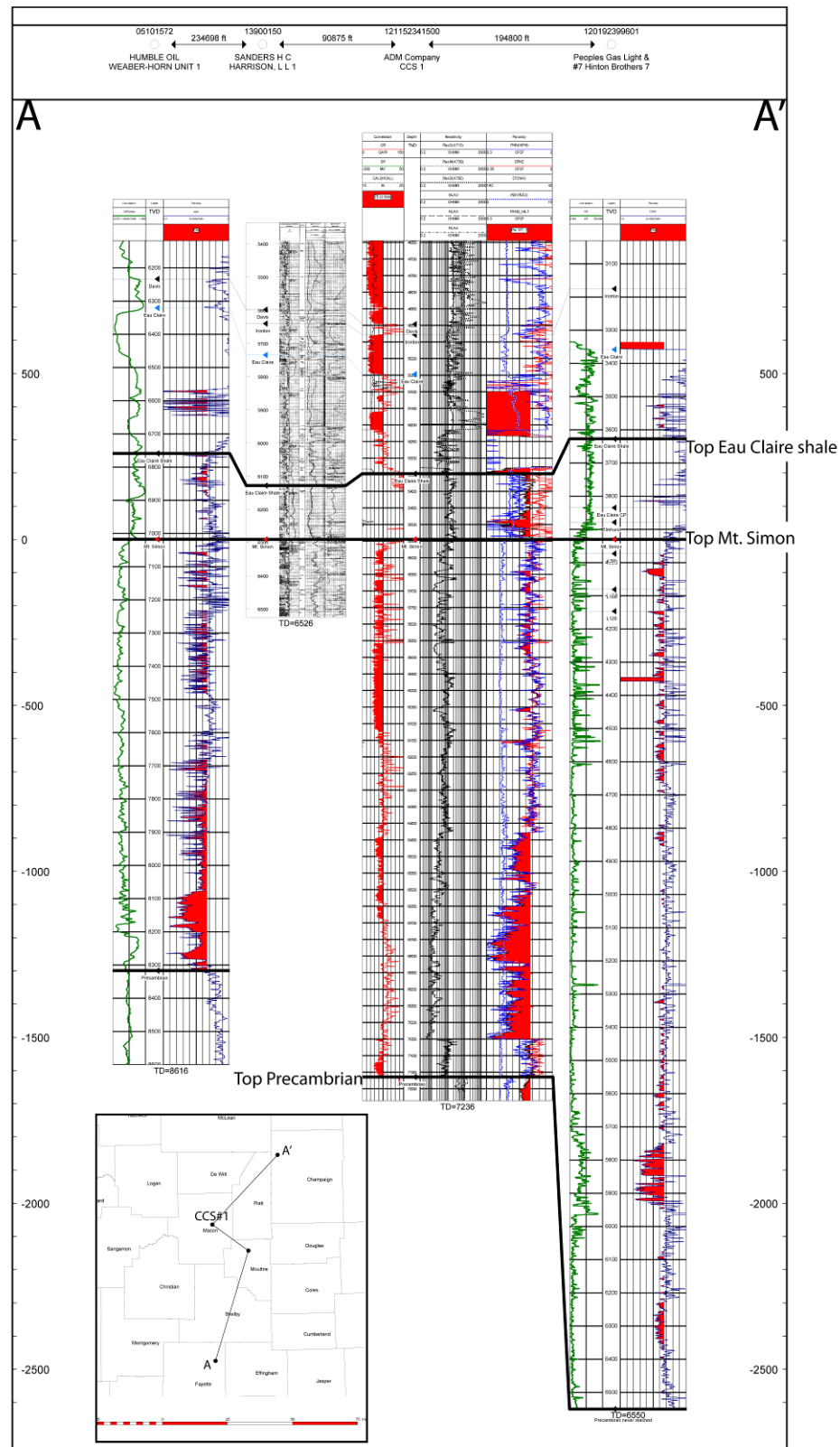
5. Distance to nearest downgradient water supply well

See the Feasibility Report for a discussion regarding data on the nearest water supply well.

VIII. Minerals and Hydrocarbons

See the Feasibility Report for a description of Mineral and Hydrocarbon resources in the area.

Figure 4a1: A north-south trending cross section across the Hinton #7, CCS#1, Harrison #1, and Weaber-Horn #1 (see A-A' in Figure CCS1_hinton_xsd_Mehnert.pdf)



CHRONOSTRATIGRAPHIC UNITS						NORTHERN ILLINOIS (north of 40° North latitude)		
GLOBAL			NORTH AMERICAN					
SYSTEM	SERIES	STAGE	SYSTEM	SERIES	STAGE	Sequence	Group	
ORDOVICIAN	UPPER	STAGE 6	ORDOVICIAN	LLANOCYBER		Maquoketa	Formation and thickness Selected members and beds *Oil well driller's terms shown in quotation marks	
				RHODANIAN			Kankakee Dol 0 -80'	Plaines Mbr Tremont Mbr Offerman Mbr Orrumond Mbr
							Nada Fm 0 -15'	Elwood Dol 0 -30'
							Brainard Sh 0 -100'	Birds Mbr
							Pl. Atkinson Ls 0 -60'	Wilhelm Fm 0 -100' Schweizer Mbr
	LOWER	STAGE 5	ORDOVICIAN	ALEXANDRIAN		Tiptonance 1	Scales Sh 0 -135'	
				RICHMONDIAN			Dubuque Fm 0 -40'	
							Wibe Lake Fm 0 -80'	
							Dunkirk Fm 0 -35'	
							Dacorch Fm 0 -25'	Guttenberg Dol Milburg R-bentonite bed Specht Perry Sh
TREMACOCCAN	UPPER	STAGE 4	ORDOVICIAN	CINCINNATIAN		Platteville	Quimbys Mbr Fm 0 -30'	
				EDGEMAN			Natchusa Fm 0 -40'	
							Grand Detour Fm 0 -180'	
							Mt. Airy Fm 0 -30'	
							Pacatonia Fm 0 -50'	
	LOWER	STAGE 3	ORDOVICIAN	MOHAWKIAN		Ancell	Joachim Dol 0 -50'	
				TURNIAN			Glenwood Fm 0 -75'	
							St. Peter Ss 0 -600'	
							Trent Mbr	
							Knox Mbr	
TREMACOCCAN	STAGE 2	ORDOVICIAN	IBERIAN		Sauk	Shakopee Dol 0 -500'		
						New Richmond Ss 0 -150'		
						Onondaga Dol 0 -300'		
TREMACOCCAN	STAGE 1	ORDOVICIAN			Prairie du Chien	Gunter Ss 0 -25'		



Figure 4a3: ADM CCS#1 step-rate test with fracture propagation pressure of 4966 psig estimated from the intersection of the two lines. The first line (2-6 bpm) represents radial flow of the Mt. Simon; the second line 7-8 bpm represents flow into the Mt. Simon after a fracture has propagated. The perforated interval was 7,025 to 7,050 feet during this step-rate test. (see Frailey_completionreport_0310.xls for original plot)

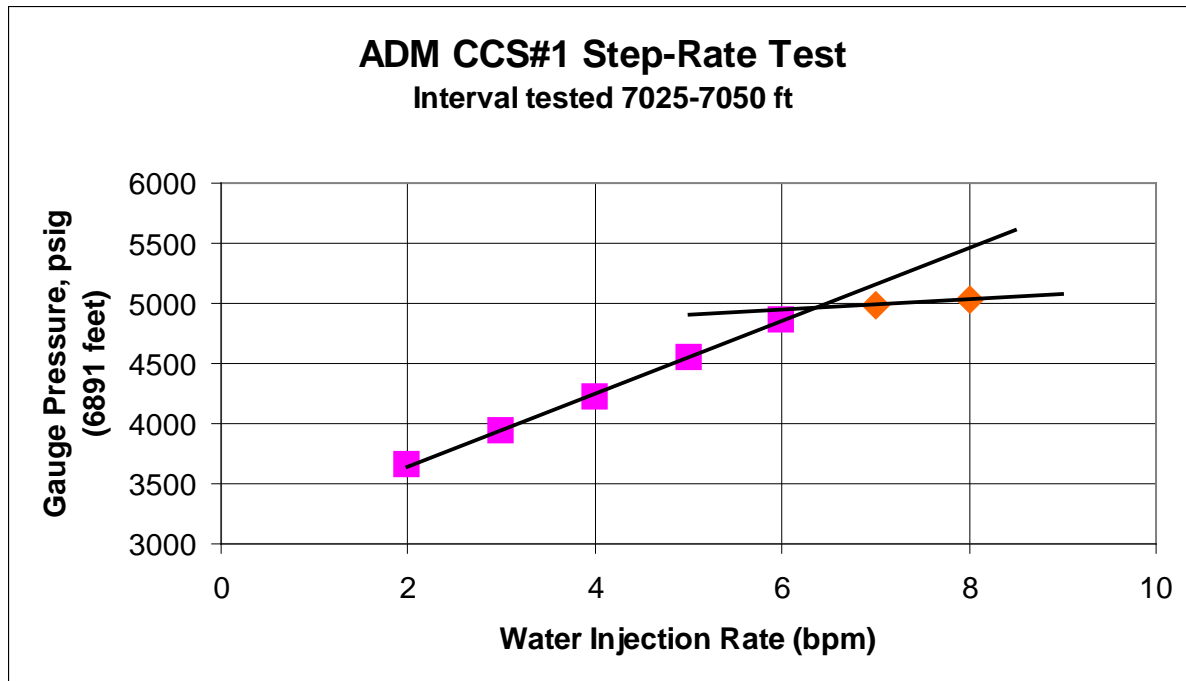


Figure 4a4: The bold line through the data is the unit slope, showing very good correlation between the two types of porosity data. For the porosity data from the rotary sidewall core plugs and the neutron-density crossplot porosity at the interval of the core plug, the porosity compares relatively well such that total and effective porosity are very similar. (see Frailey_completionreport_0310.xls for original plot)

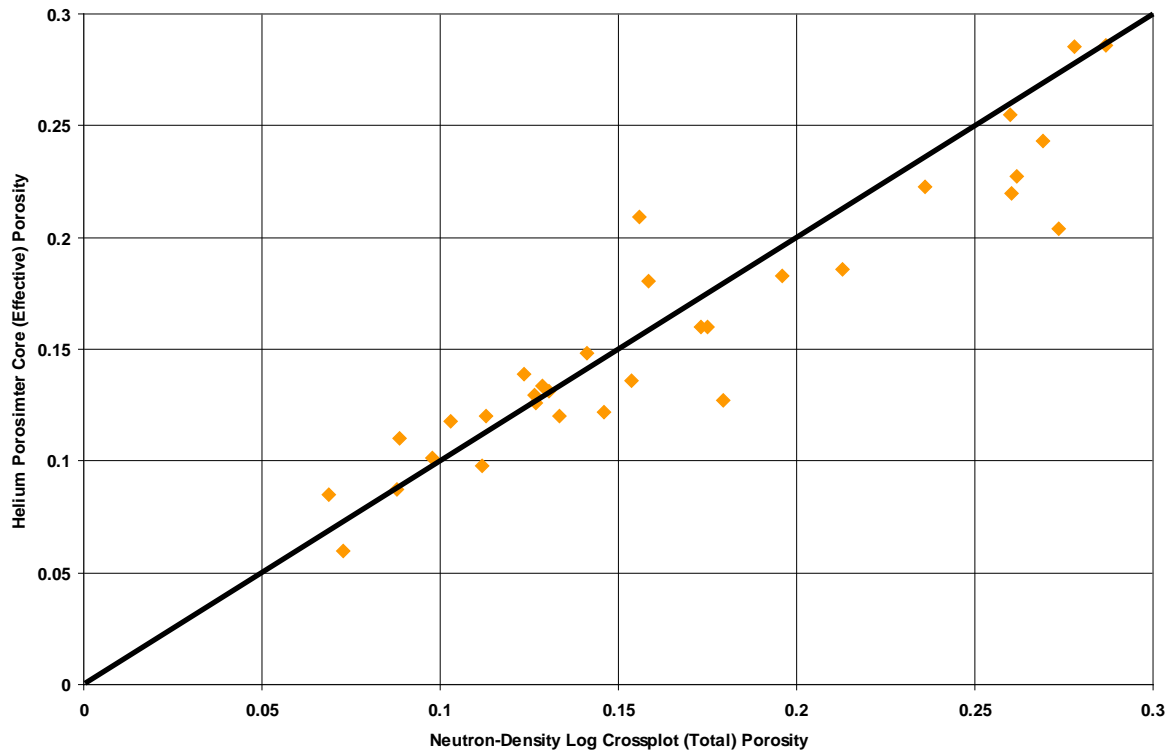


Figure 4a5. Crossplot of core permeability versus core porosity. Transforms were developed for three different grain sizes—fine grained, medium grained and coarse grained sandstone. (see frailey_completionreport_0310.xls for original plot)

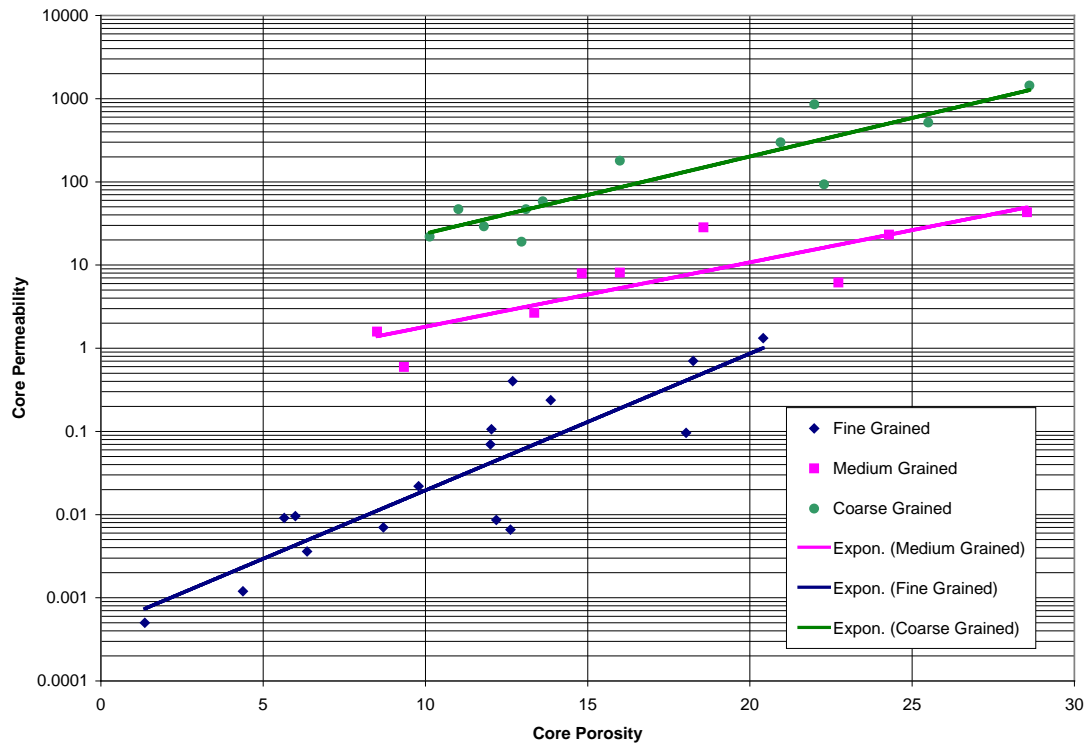


Figure 4a6: Qualitative derivative analyses of final pressure falloff test. Radial pressure response is indicated by a horizontal derivative trend. Two periods were measured during this test between 0.1 and 1 hours (PPNSTB) and 20 to 100 hours (STABIL). The first period corresponds to radial flow across the perforated interval; the second period corresponds to the larger thickness that would be between two much lower permeability sub-units e.g, the low perm granite wash at the base. The transition between the two radial responses (SPHERE) is a spherical flow period that is influenced by vertical permeability (or k_v/k_h). (The unit slope (UNIT SLP) indicating wellbore storage, identifies the end of wellbore storage influenced pressure data (ENDWBS) or pressure data that can be analyzed from reservoir properties.)

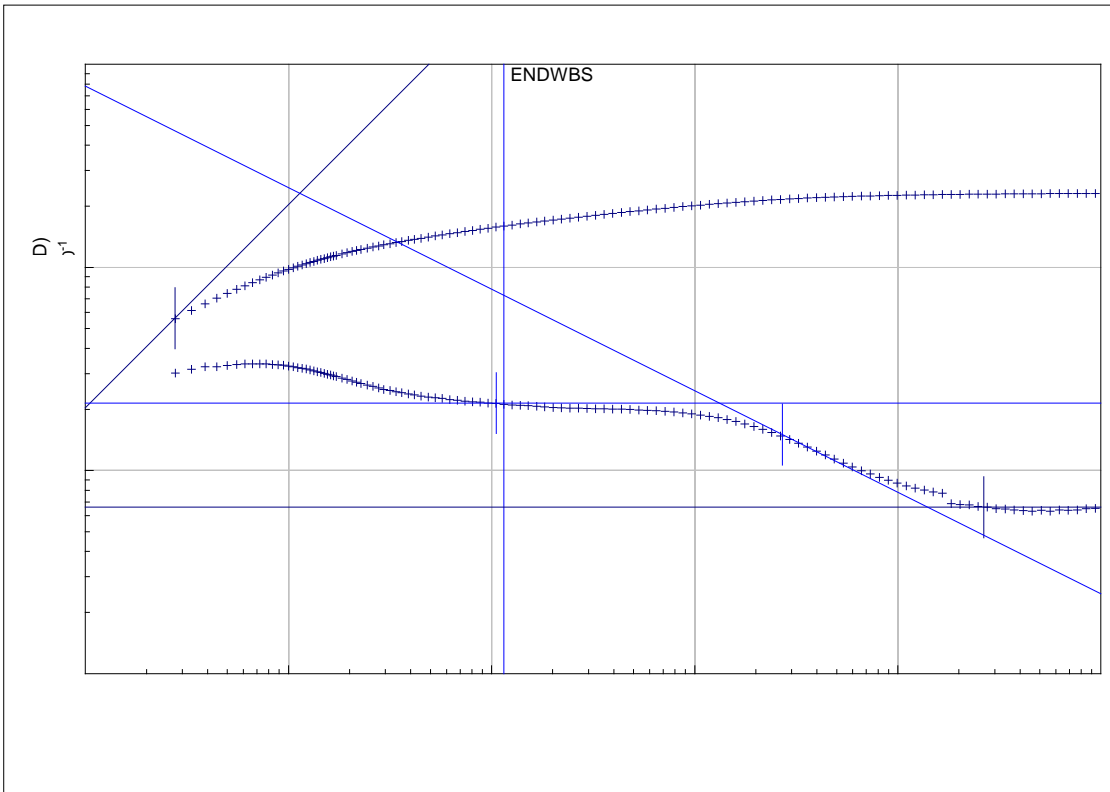


Figure 4a7: Overlay of pressure derivative of the three pressure falloff tests. The Green curve (upper pressure curve and bell shaped derivative) is the first falloff which had perforated interval of 7025-7050 ft MD. The pink (lower derivative curve) is the second falloff in the same perforated interval which had a modest acid treatment prior to the falloff. The dark blue (lower pressure curve middle derivative curve) was the third falloff tests for the perforated intervals of 6982-7012 and 7025-7050 ft MD and a second acid treatment over both perforated intervals. The difference between the green curve and the pink curve in the first 6 minutes is a result of the improvement to flow due to the acid treatment. The upper curves show the pressure difference and the lower curves show the derivative.

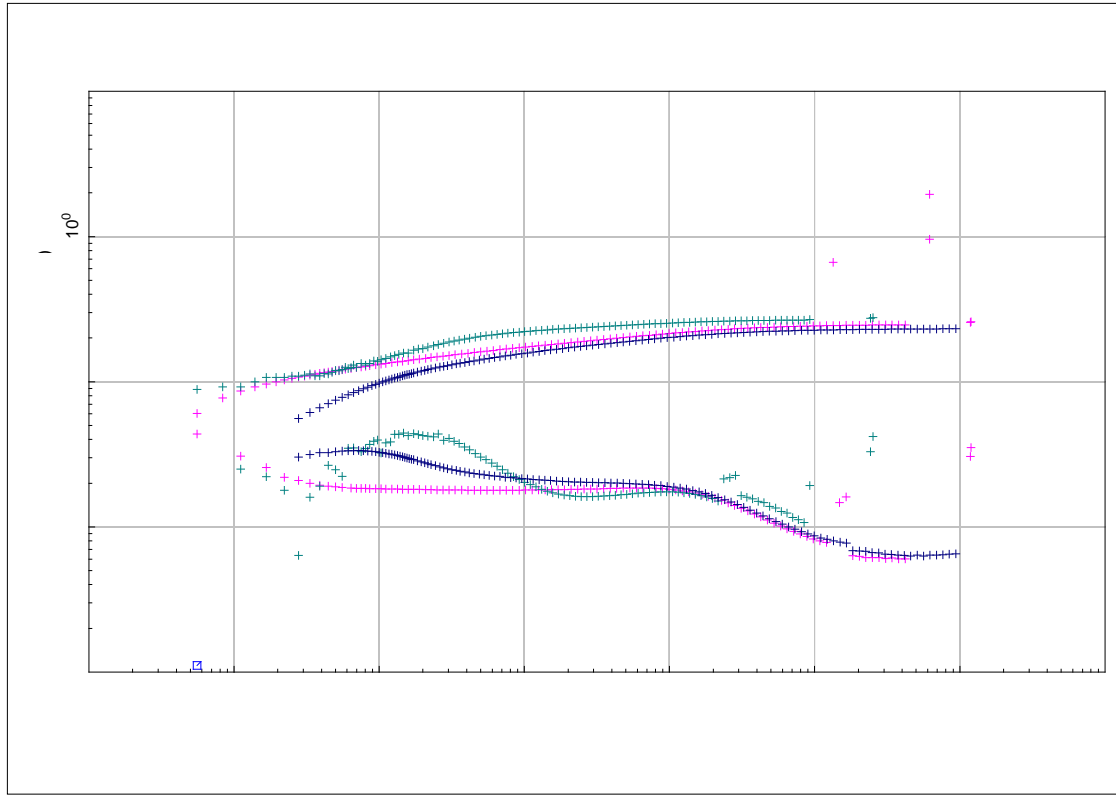
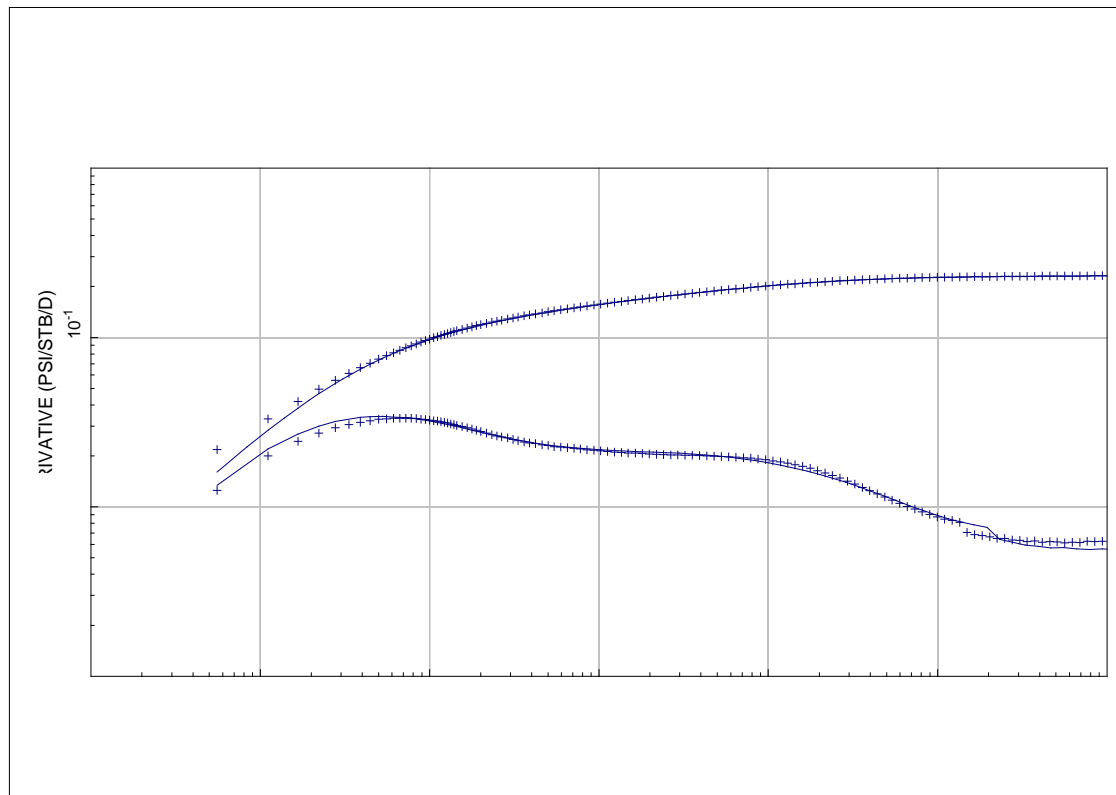


Figure 4a8: Nonlinear regression, or simulation history matching, of the of final pressure falloff test. Test data shown as + symbols and simulated data shown as line. The upper curve is the pressure difference and the lower curve is the derivative.



Partial Penetration Well

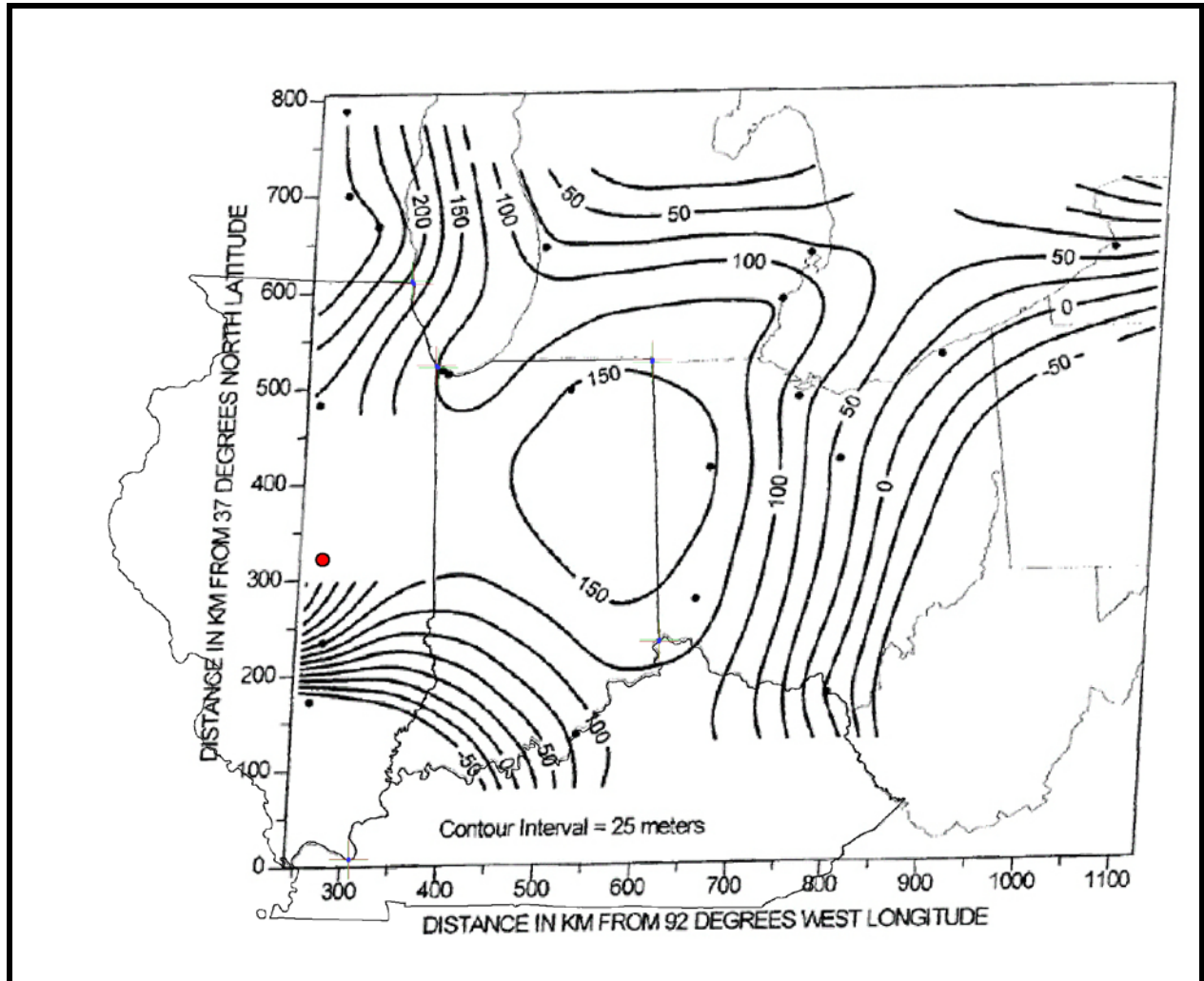
** Simulation Data **

well storage = 0.0011457 BBLS/ PSI
 Skin(mech.) = -0.85807
 permeability = 184.58 MD
 Kv/ Kh = 0.013260
 Eff. Thickness = 75.000 FEET
 Zp/ Hef f = 0.83330
 Skin(Global) = 10.301
 Perm Thickness = 13843. MD- FEET

Type- Curve Model Static- Data
 Perf. Interval = 25.0 FEET

Static- Data and Constants
 Volume- Factor = 1.000 vol / vol
 Thickness = 75.00 FEET
 Viscosity = 1.300 CP
 Total Compress = .1800E-04 1/ PSI
 Rate = -6100. STB/ D

Figure 4a9. Potentiometric surface in the Mt. Simon Sandstone in Indiana, Ohio and surrounding states (modified from Gupta and Bair, 1997). The red dot shows the location of the ADM site in east-central Illinois. At the ADM site, the potentiometric surface was calculated to be 76 m above mean sea level.



Appendix XIII.B – Revised UIC Form 4d

7 UIC Form 4d, Area of Review

Last revised: 4/1/2010

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT APPLICATION

FORM 4d - AREA OF REVIEW

USEPA I.D. NUMBER ILD984791459
IEPA I.D. NUMBER 1150155136
UIC Well Number CCS #1

I. Radius of the Area of Review

A fixed radius of 2.5 miles was selected for the area of review.

II. Method of Radius determination

A fixed radius of 2.5 miles was selected for the area of review.

III. Map with information required by Section 730.114(a)(2) or 730.134(a)(2)

See the Feasibility Report for a discussion regarding maps of wells within the area of review. As discussed in the Feasibility Report, a total of 1,034 wells are known to be drilled within the area of review. The deepest well is 2,500 feet. Sixty-five oil wells within the Area of Review have been drilled to the depth range of 2,100 to 2,500 feet.

IV. Description of Anticipated Injection Fluid Movement during the Life of the Project

VIP reservoir simulator from Landmark Graphics
(<http://www.halliburton.com/ps/Default.aspx?navid=226&pageid=888&prodid=MSE%3a%3a1055451807810981>) was used to estimate the plume migration around the proposed site. The proposal requires a minimum injection volume of 1.0 million metric tonnes (Mt). The geologic model was based on the open-hole well logs and the core analyses of CCS#1, verified with the water pressure transient injection falloff test. The structure was based on interpretation of two, 2-D seismic survey lines acquired prior to drilling the well and discussed in the Feasibility Report

The geologic model included the entire Mt. Simon from the base of the Eau Claire to the top of the granite. The Mt. Simon was divided into 108 vertical layers, with each layer being 15 feet thick.

For the simulation, CO₂ was injected at 0.333 Mt per year for three years. The lowest part of the Mt. Simon was used for injection. CO₂ could move vertically into higher parts of the Mt. Simon but not via the wellbore. Following three years of injection, two years of shut-in were also simulated.

Several models of varying model cell size and perforation strategies were used. Based on model results, the plume radius is expected to be approximately 1,500 feet. Because the injection interval is low within the gross thickness of the Mt. Simon, CO₂ flows upward from the injection interval. The CO₂ saturation increases below relatively lower permeability subintervals within the Mt. Simon. After three years of continuous injection into the lower part of the Mt. Simon and two years of shut-in, the CO₂ never reaches the caprock at the end of injection.

V. Wells Within the Area of Review

A. *Tabulation of well data required by 730.114(a)(3) or 730.134(a)(3)*

See the Feasibility Report for a tabulation of wells located within the 2.5 mile area of review.

B. *Number of wells within 2 1/2 miles of injection well penetrating within 300 feet of the uppermost injection zone which are:*

1. *Properly plugged and abandoned – N/A*
2. *Temporarily abandoned – N/A*
3. *Operating – N/A*
4. *Improperly sealed, completed or abandoned – N/A*

As discussed in the Feasibility Report, there are no known wells within the 2.5 mile area of review that penetrate deeper than 2,500 feet. The depth to the top of the injection zone (Mt. Simon Sandstone) is 5,545 feet. Therefore, there are no known wells that penetrate within 300 feet of the uppermost injection zone.

C. *Plugging affidavits for all plugged wells*

See the Feasibility Report for the plugging affidavit for one plugged well located within the 2.5 mile area of review.

D. *Proposed corrective action for unplugged wells penetrating the injection zone*

See the Feasibility Report for a discussion of wells that required corrective action.

Appendix XIII.C – Revised UIC Form 4g

10 UIC Form 4g, Plugging and Abandonment

Last Revised: 3/31/2010

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT APPLICATION

FORM 4g - PLUGGING AND ABANDONMENT PROCEDURE

USEPA I.D. NUMBER ILD984791459
IEPA I.D. NUMBER 1150155136
UIC Well Number CCS #1

I. Description of Plugging Procedures, see instructions

The plugging and abandonment design reflects minimum requirements to sustain the integrity of the caprock to ensure CO₂ remains in the Mt. Simon. Any unforeseen changes necessary to plug and abandon this well will meet or exceed these requirements in terms of strength or CO₂ compatibility. Appendix E has the Engineering Technical Report signed and sealed by an Illinois Registered Professional Engineer.

A. Abandonment during construction

Removal of subsurface well features: There are three scenarios in which abandonment during well construction (or drilling) and completion while the wellbore is open or uncased: Drilling the Surface Hole (<300 ft MD), Drilling Intermediate Hole (<5,000 ft MD), and Drilling Long-String Hole (<7,500 ft MD).

During all three scenarios, the drill string (drill collars, drill pipe, and drill bit) is the most likely equipment in the hole. Every attempt will be made to recover all of this equipment prior to abandonment.

If drill pipe, drill collars and/or drill bit are not retrieved and must be abandoned in the wellbore, no unique plugging procedure is required and plugs will be placed as described in the UIC permit application (4g.I.C). The same procedure will be used in the scenario where any testing tool, such as a core barrel, drill stem test assembly, or non-radioactive well logging tool, cannot be retrieved or is abandoned in the well.

If a radioactive well log is lost in the hole (density and/neutron porosity), current Nuclear Regulatory Commission (NRC) regulations will be followed. A 300 foot, red cement plug will be placed immediately above the lost logging tool. An angled, kick-plate will be placed above this plug to divert any subsequent drilling that may coincidentally enter this wellbore. Current NRC regulations require that the surface casing remain extended above the ground surface with an informative ground plate welded to the pipe. The plate includes information about the well to identify what is in the hole.

Plug Placement Method: The method of placing the plugs is the **Balanced Plug** method. This is a basic plug spotting process that is generally considered more efficient and considered compliant with accepted industry practices.

B. Abandonment after injection

Removal of subsurface well features: Casing: All casing used in this well will be cemented to surface and will not be retrievable at abandonment after injection.

Tubing and Packer: After injection, the injection tubing and packer will be the only injection equipment in the cased hole. Every attempt will be made to remove the injection tubing and packer. If the packer cannot be released and removed from the cased hole, an electric line with tubing cutter will be used to cutoff the tubing above the single packer.

Plug Placement Method: The **Balanced Plug** placement method will be used. This is a basic plug spotting process that is generally considered more efficient and considered compliant with accepted industry practices.

C. Type and quantity of plugging materials, depth intervals

In addition to the proper volumes, placement of plugs on depths approved by the agency (the minimum requirements), all cement will be previously tested in the lab, a Schlumberger CemCADE will be performed using actual well information such as actual depth, temperature on bottom, hole conditions. During the plugging operations, both wet and dry samples will be collected for each plug spotted to ensure quality of the plug.

All casing will be cemented to surface and no casing will be retrieved. From the surface, at least 3 feet of all the casing strings will be cutoff well below the plow line and a blanking plate with the required permit information will be welded to the top of the cutoff casing.

D. Detailed plugging and abandonment procedures

Notifications, Permits, and Inspections (Prior to Workover or Rig Movement)

Notifications, Permits, and Inspections are the same for plug and abandonment during construction and post-injection.

1. Notify Illinois EPA 48 hours prior to commencing operations. Insure proper notifications have been given to all regulatory agencies for rig move.
2. Make sure all permits to P&A have been duly executed by all local, State & Federal agencies and ADM have written permission to proceed with planned ultimate P&A procedure.
3. Ensure in advance that a pre-site inspection has been performed and the rig company has visited the site and is capable of transporting rig, tanks & ancillary equipment to perform P&A operations. Notify all key third parties of expected work scope, and ensure third party contracts for work are in place prior to move in.

4. Have copies of all government permits prior to initiating operations and maintain on location at all times. Check to see if conditions of approval have been met.
5. Make sure partners (U.S. DOE, IEPA and ADM) approvals have been obtained, as applicable.
6. Make sure all necessary forms for Schlumberger paperwork are on the rig, i.e., NPDES, safety meetings, trip sheets, etc.

Table 1: Plugging & Abandonment Contact List

<u>Name</u>	<u>Department/Pos</u>	<u>Office</u>	<u>Fax</u>	<u>Mobile</u>	<u>Home</u>
Paul Hughes, Jr., P.E.	Schlumberger- Operations	281-340- 8658	281-285- 0165	832-715- 9060	281-781- 8545
Robert J. Finley	ISGS Project Management	217-244- 8389	217-333- 2830	217-649- 1744	217-384- 6841
Tom Stone	ADM Project Engineer	217-424- 5897			
Mark Carroll	ADM Environmental Coordinator	217-451- 2720			
Kevin Lesko	Illinois Environmental Protection Agency	217-524- 3271	217-524- 3291		
	Federal Regulatory				

Volume Calculations

Volumes will be calculated for specific abandonment wellbore environment based on desired plug diameter and length required. Volume calculations are the same for plug and abandonment during construction and post-injection.

1. Choose the following:
 - a. Length of the cement plug desired.
 - b. Desired setting depth of base of plug.
 - c. Amount of spacer to be pumped ahead of the slurry.
2. Determine the following:
 - a. Number of sacks of cement required.
 - b. Volume of spacer to be pumped behind the slurry to balance the plug.

- c. Plug length before the pipe is withdrawn.
 - d. Length of mud freefall in drill pipe.
 - e. Displacement volume required to spot the plug.
3. See generic calculations in Figure 51 and have Schlumberger cementer and wellsite supervisor both review calculations prior to spotting any plug.

Note: For each cementing operation the Schlumberger cementer and the wellsite supervisor will verify via the cementing handbook or iHandbook all calculations and have the Project Manager approve the manner and procedure for said cementing operations. Any amendments to the plugging program will require an exemption approved in writing from the Project Manager.

Plugging and Abandonment Procedure for “During Construction” Scenario:

Pumping the Cement Job (Figure 52)

1. Trip in Hole (TIH) to the desired depth (drill pipe tags the base of the desired plug depth).
2. Shut down circulating trip tank on wellbore.
3. Break circulation and condition mud as required. Circulate at least until the pit levels stabilize.
4. Mix and pump cement and spacers.
5. Displace with the predetermined mud volume.
6. Shut down cementing unit and allow mud to freefall.
7. Near the end of the freefall, begin pulling out. Check to verify if we are pulling dry or wet.

Pulling Out of the Plug (Figure 52)

8. Resume circulating trip tank on the wellbore. Slowly pull the drillstring out of the plug and continue trip out of hole (TOH) until 2-3 stands above the top of the plug. Slowly pump 5-10 bbls to clear the drill pipe. Run circulating trip tanks continuously.
9. Do not attempt to reverse circulate because of potential contamination of the cement plug and to avoid over-pressuring the wellbore annulus. TOH.
10. Waiting on cement (WOC) minimum 12 hours, make up bottom hole assembly (BHA) and TIH to tag plug and record same. If tag will hold 5-10K lbs weight, pull up, circulate 1-2 stands above and continue with next balanced plug (either in open hole or inside casing) to properly comply with all local, state and federal regulations governing P&A operations (Table in Form 4g.I.C).
11. After spotting of all plugs, pull out of hole (POOH) laying down all drill pipe and drill collars, break out BHA
12. Finish cutting off below plow line (or per local, state or regulatory guidelines) all casing, dump 2-5 sacks of G cement in surface hole below plow line and weld plate on top of casing stub. Place marker as required by agencies.

13. After rig is released, commence with restoring site to as original condition as possible or per local, state or federal guidelines.
14. Complete plugging forms and send in with charts and all lab information to all state, local or federal agencies, as is required.

Plugging and Abandonment Procedure for “After Injection” Scenario:

1. Mobilize workover (WO) or Plugging Rig Equipment. Give IEPA and DNR 48 hours notice before commencing operations.
2. Move in rig to ADM CCS#1 location. Notify the Project Coordinator before moving rig. Ensure all overhead restrictions (telephone, power lines, etc) have been adequately previewed and managed prior to move in and rig up (MI & RU). All CO₂ pipelines will be marked and noted to WO rig supervisor prior to moving in (MI) rig. Move rig onto location per operational procedures.
3. Conduct a safety meeting for the entire crew prior to operations, record date and time of all safety meetings and maintain records on location for review.
4. Make daily “Project Inspection” walks around the rig. Immediately correct deficiencies and report deficiencies during the regulatory discussion during morning meetings/calls. Maintain International Association of Drilling Contractors (IADC) or plugging reports daily at the WO rig log book or doghouse.
5. MI rig package and finish rigging up hoses, hydraulic lines, etc.
6. Open up all valves on the vertical run of the tree. Check pressures.
7. Rig up pump and line and test same to 2,500 psi. Fill casing with kill weight brine (9.5 ppg). Bleeding off occasionally may be necessary to remove all air from the system. Keep track and record volume of fluid to fill annulus (Hole should be full). If there is pressure remaining on tubing rig to pump down tubing and inject two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour. If both casing and tubing are dead then nipple up blowout preventers (NU BOP's). Monitor casing and tubing pressures.
8. If needed, if well is not dead nor pressure cannot be bled off of tubing, rig up (RU) slickline (SL) and set X-lock plug in X nipple located in X-Plug in tailpipe below packer. Circulate well with kill weight brine. Ensure well is dead. ND tree. NU BOP's and function test same. BOP's should have 4 1/2" single pipe rams on top and blind rams in the bottom ram for 4 1/2" Test BOP's as per local, state or federal provisions or utilize higher standard, 30 CFR250.616. Test pipe rams and blind rams to 250 psi low, 3,000 psi high. Test annular preventer to 250 psi low and 3,000 psi high. Test all TTW's, IBOP's choke and kill lines, choke manifold, etc. to 250 psi low and 3,000 psi high. **NOTE: Make sure casing valve is open during all BOP tests.** After testing BOPs pick up 4 1/2 tubing string and unlatch seal assembly from seal bore. Rig slick line and lubricator back to well and remove X- plug from well. Rig to pump via lubricator and keep well dead.

9. RU 4 1/2" rig hydraulic tubing tongs for handling of production tubing. Pick back up on tubing string and pull seal assembly from seal bore. Pull hanger to floor and remove same. Circulate bottoms up with packer fluid.
10. POOH with tubing laying down same. **NOTE: Ensure well does not flow due to CO₂ "back flow"! Well condition is to be over-balanced at all times with at least 2 well control barriers in place at all times.**

Contingency: If unable to pull seal assembly RU electric line and make cut on tubing string just above packer. Note: Cut must be made above packer at least 5-10 ft MD. Several different sizes of cutters and pipe recovery tools should be on location due to possible tight spots in tubing.

11. If successful pulling seal assembly then pick up 3 1/2 or 4 1/2 inch workstring and TIH with Quantum packer retrieving tools. If tubing was cut in previous step then skip this step. Latch onto Quantum packer and pull out of hole laying down same. If unable to pull Quantum pull work string out of hole and proceed to next step. Assuming tubing can be pulled with packer with no issues, run CBL or USIT to determine that there is no leakage around the wellbore above the caprock. If leakage is noted prepare cement remediation plan and execute during plugging operations. Set 9 5/8 inch cement retainer on wireline just in Eau Claire above the Mt Simon Formation (approximately 5250 feet). Trip into hole with work string and sting into cement retainer. Test backside to 750 psi for 30 minutes on chart. A successful test should have less than 10% bleed off over the 30 minute period. This will be considered a successful casing test. Establish injection with packer kill fluid at 0.5, 1, and 2 BPM not to exceed 2,000 psi injection pressure. Sting out of retainer.
12. With pipe stung out of retainer, Mix and pump 300 (63 bbls) sacks of Class "H" cement mixed at 15.6 ppg plus fluid loss additive as proposed by cementing company and actual downhole conditions (temperature, BHP, etc). Obtain fluid loss of less than 100 cc/30 min. Follow that with 500 (105 bbls) sacks Class H cement mixed at 15.6 ppg with dispersant. Circulate to within 5 bbls of end of work/tubing string, sting into retainer and finish mixing cement. Displace tubing and squeeze away 30 bbls of cement into the open perforations.. Note: Do not squeeze at higher pressures than 2,000 psi. Sting out of retainer and reverse out a minimum of 2 pipe volumes. **Note: Leave cement on top of retainer.**
13. POOH racking back work string. Shut down for 12 hours Go in hole (GIH) open ended. Tag up on cement on top of retainer and note same.
14. Circ well and ensure well is in balance. Place tubing just above cement top from previous day. Mix and spot 500 ft balanced plug in 9 5/8 inch casing (approximately 175 sacks Class A or H). Pull out of plug and reverse circulate tubing. Repeat this operation until a total of 10 plugs have been set. If plugs are well balanced then the reverse circulation step can be omitted until after each third plug. Lay down work string while pulling from well. If rig is working daylight only then pull 10 stands and rack back in derrick and reverse tubing before shutting down for night. The following morning trip back in hole and tag plug and continue. After ten plugs have been set pull tubing from well and shut in for 12 hours. Trip in hole with tubing and tag cement top. Calculate volume for final plug. Pull tubing back out of well. Nipple down BOPs and cut all casing strings below plow line (min 3 feet below

ground level or per local policies/standards and ADM requirements). Trip in well and set final cement plug. Total of approximately 2660 sacks total cement used in all plugs. Lay down all work string, etc. Rig down all equipment and move out. Clean cellar to where a plate can be welded with well name onto lowest casing string at 3 ft.

15. File all plugging forms to local state, federal and other agencies as required.

Note: utilize all local, state or federal rules relative to P&A or at least 33% plus actual volumes or as approved previously by Illinois state agency or Federal agency.

E. Cost estimate for plugging and abandonment worst case scenario

Itemized P&A Costs	During Construction	Post Construction*
a. Casing Evaluation:	N/A	\$50,000
Mobilize equipment and crews from nearest district. Run multi-finger caliper for detailed inspection of the inner surface of the casing. Run Isolation Scanner for final condition of outer surface of casing and cement condition. Compare to baseline logs run before injection started.		
b. Evaluation of any problems discovered by the casing evaluation:	N/A	\$20,000
Downhole video camera to get visual images of the questionable inner surfaces of the casing.		
c. Cost for repairing problems and cleanup of any groundwater or soil contamination:	N/A	\$40,000
CO ₂ as a vapor in soil would not result in contamination like a liquid. A formal "cleanup" may not be required, and the CO ₂ would dissipate into the atmosphere.		
CO ₂ into groundwater would like be the same as that in oil. For a period of time, the shallow groundwater may have a low concentration of CO ₂ similar to a "flat" soft drink. With time the CO ₂ will dissipate into the unsaturated soil and dissipate.		
d. Cost for cementing or other materials used to plug the well:	\$37,000	\$78,000
e. Cost for labor, engineering, rig time, equipment and consultants:	\$157,000	\$157,000

f. Cost for decontamination of equipment:	N/A	N/A
--	-----	-----

g. Cost for disposal of any equipment:	N/A	\$2,000
---	-----	---------

Tubing would be sold as scrap metal and worst case cost would be trucking services only.

h. Estimated sales tax:	\$2,000	\$2,000
--------------------------------	---------	---------

Our review shows there is no state sales tax for this kind of work.

i. Miscellaneous and minor contingencies (20%):	\$10,000	\$10,000
--	----------	----------

j. Total	\$206,000	\$359,000
-----------------	-----------	-----------

* Post Construction cost is for 1/1/08; if the well was abandoned 30 years from now, assuming 3% annual inflation the worst case P&A would be 2.43 times greater or \$873,370.

Figure 51: Plugging Volume Calculations

VOLUME CALCULATIONS	
1. CAPACITIES	
Determine the following capacities:	
Annular capacity between drillpipe and hole (V_{ANN})	ft ³ /ft and ft/bbl
Hole or casing capacity (V_{CAPOH})	ft ³ /ft
Drillpipe or tubing capacity (V_{CAPDP})	ft ³ /ft and bbl/ft
2. NUMBER OF SACKS OF CEMENT	
Determine the number of sacks of cement required for a given length of plug (sx):	
N_{SX}	= $L_{PLUG} \times V_{CAPOH} / \text{slurry yield}$
Where:	
N_{SX}	= number of sacks of cement, sx
L_{PLUG}	= length of cement plug, ft
V_{CAPOH}	= capacity of open hole or casing, ft ³ /ft
Slurry yield	= cement yield, ft ³ /sk
3. SPACER VOLUME BEHIND SLURRY	
Determine the spacer volume to be pumped behind the slurry to balance the plug (bbls):	
$V_{TAILSPACER}$	= $V_{ANN} \times V_{LEADSPCR} \times V_{CAPDP}$
Where:	
$V_{TAILSPACER}$	= spacer volume to be pumped behind the slurry to balance the plug, bbls
V_{ANN}	= annular capacity, ft/bbl
$V_{LEADSPCR}$	= spacer volume to be pumped ahead of cement plug, bbls
V_{CAPDP}	= drill pipe capacity, bbl/ft

Figure 51: Plugging Volume Calculations, contd.

VOLUME CALCULATIONS, CONTINUED

4. PLUG LENGTH

Determine the **plug length (ft)** before the drill pipe is withdrawn (ft):

$$L_{\text{PLUG}} = (N_{\text{SX}} \times \text{slurry yield}) / (V_{\text{ANN}} + V_{\text{CAPDP}})$$

Where:

L_{PLUG} = length of cement plug before the DP is withdrawn, ft

N_{SX} = number of sacks of cement, sx

Slurry yield = cement yield, ft³/sk

V_{ANN} = annular capacity, ft³/ft

V_{CAPDP} = drill pipe capacity, ft³/ft

5. LENGTH OF FREEFALL IN DRILL PIPE

Determine the **length of mud free fall in drill pipe (ft)**:

$$L_{\text{FF}} = \text{TD} (1 - \text{MW})$$

Where:

L_{FF} = length of free fall inside the drill pipe, ft

TD = depth, ft

MW = mud density, pPG

6. DISPLACEMENT VOLUME

Determine **displacement volume** required to spot the plug (bbl):

$$V_{\text{DISP}} = [(L_{\text{DP}} - L_{\text{PLUG}} - L_{\text{FF}}) \times V_{\text{CAPDP}}] - V_{\text{TAILSPCR}}$$

Where:

V_{DISP} = displacement volume required to spot cement plug, bbls

L_{DP} = length of drill pipe, ft

L_{PLUG} = length of cement plug, ft

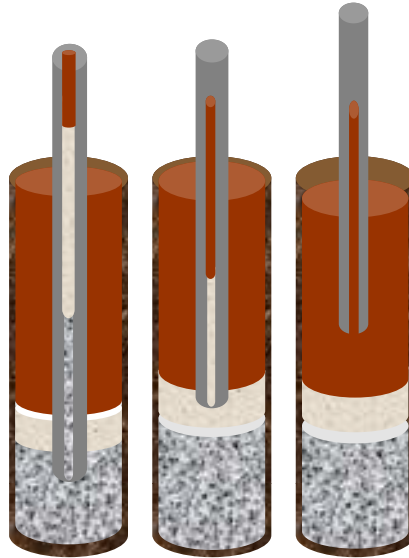
L_{FF} = length of freefall, ft

V_{CAPDP} = drill pipe capacity, bbl/ft

V_{TAILSPCR} = spacer volume to be pumped behind the slurry to balance the plug, bbls

Figure 52: Schematic of pumping the cement job using the balanced plug method.

The mottled grey is cement, the white is spacer, and the brown is mud. In the first graphic, the first spacer has already been pumped, and they are pumping in the cement. In the 2nd graphic, they have displaced most of the cement (don't want to contaminate the cement, so leave a little in pipe at this stage), pulled the end of the pipe up into the space, and are displacing the end of the cement and putting more spacer fluid in between the mud and the cement. In the 3rd graphic, they are circulating mud to clean the pipe and casing of any cement before it sets.



Appendix XIID – D.N.R. Well Completion Report Form



Archer Daniels Midland Company
P.O. Box 1470, Decatur IL 62525

May 16, 2011

Mr. Steve Nightingale
Illinois Environmental Protection Agency
Bureau of Land, Permit Section #33
1021 N. Grand Ave. East
P.O. Box 19276
Springfield, IL 62794-9276

Via Certified Mail

Re: Permit No. UIC-012-ADM
CCS1 Well Completion Report Supplemental

Dear Mr. Nightingale:

ADM submitted the Well Completion Report for the CCS#1 injection well on May 5, 2010. Recently, a review of the report has been completed to ensure all required information is included.

The surface facility was the primary area of emphasis since it was not physically completed at the time of the initial report submittal. The surface facility is now substantially complete. Review of IEPA UIC Form 4H and the permit requirements concludes that the required information was provided for the surface facility in the May 5, 2010 submittal and no additional information is required to meet those requirements.

Condition B.6 of the March 25, 2011 permit requires submission of the well completion report for CCS#1. The condition requires "A descriptive report interpreting the results of the logs and tests that has been prepared by a knowledgeable log analyst shall be included." It was identified that the original report did not include this descriptive report. A copy of this report is included with this submittal as a supplement to the May 5, 2010 completion report.

With this supplement, ADM believes the completion report is complete. ADM requests the Agency complete its review of the well as soon as possible as a request for approval to inject will

also be submitted soon. If you have any questions regarding this please contact Sallie Greenberg at 217-244-4068 or myself at 217-451-6330.

Sincerely,



Dean Frommelt

Division Environmental Manager

Corn Processing & BioProducts

Cc: Kevin Lesko - IEPA
Mark Burau - ADM
Mark Carroll - ADM
Rob Finley - ISGS
Sallie Greenberg - ISG

ADM CCS #1

Geophysical Log Descriptive Report

Bob Butsch – Schlumberger Carbon Services

The Logging Program

The table below identifies the logging runs made by date and depth, the tools included in each run, and the primary reason for running that logging tool.

Logging Tools by Run

Date / Depth	Logging Run	Logging tools	Data Used For:
March 9, 2009 352 - 3541 ft	PEX-AIT (Platform Express)	GR, Caliper, SP, Resistivity (Induction), Density, Neutron	Correlation, Porosity, Saturations, Hole Size
April 5, 2009 352 – 5317 ft	PEX-AIT (Platform Express)	GR, Caliper, SP, Resistivity (Induction), Density, Neutron	Correlation, Porosity, Saturations, Hole Size
	HRLA	Resistivity (Laterolog)	Resistivity - Saturation
	SonicScanner, FMI	Sonic compressional and shear, Formation Micro-Imager borehole images	Porosity, Mechanical Properties, Structure, Env. Deposition, Fractures
	CMR, ECS, HNGS	Magnetic Resonance, Elemental Capture Spectroscopy, Spectral GR	Lithology, Clay Minerals, Porosity, free and bound fluids, Permeability
	MSCT	Sidewall Coring Tool	Porosity, Permeability
April 26, 2009 5339 – 7221 ft	PEX-HRLA (Platform Express)	GR, Caliper, SP, Resistivity (Laterolog), Density, Neutron	Correlation, Porosity, Saturations, Hole Size
	Sonic Scanner, FMI	Sonic compressional and shear, Formation Micro-Imager borehole images	Porosity, Mechanical Properties, Structure, Env. Deposition, Fractures
	CMR, ECS, HNGS	Magnetic Resonance, Elemental Capture Spectroscopy, Spectral GR	Lithology, Clay Minerals, Porosity, free and bound fluids, Permeability
	MSCT	Sidewall Coring Tool	Porosity, Permeability
	MDT	Modular Dynamic Tester	Formation Pressure, Mobility
	VSIT	Versatile Seismic Imager	Tie logs to seismic

In summary the standard “Triple Combo” data of the Platform Express (PEX) run includes GR, Caliper, Resistivity, Density, and Neutron measurements and is run for basic petrophysical properties of volume of shale, basic lithology, porosity and saturations. The Gamma Ray and Resistivity are also the primary measurements used for correlation to other wells. Either an induction tool or laterolog tool are used to measure the formation resistivity depending on the conductivity of the mud system in the borehole and the conductivity of the formation water. The Elemental Capture Spectroscopy (ECS) is used to identify lithology type by measuring elemental yields and to improve the clay volume calculation. The HNGS

provides natural gamma ray spectroscopy to aid in the analysis of the different clay types and special minerals containing potassium. The Combinable Magnetic Resonance (CMR) manipulates the nuclei of hydrogen atoms by applying a strong magnetic field and RF pulses. The tool then measures the response of the nuclei to the changing magnetic field, with the resulting measurement is the T2 distribution. From this measurement porosity is derived and this porosity can be subdivided based on the T2 measurement to provide information on the pore size distribution, and what portion of the fluid in the porosity is bound fluid and what is free fluid. This measurement is also used to calculate a continuous permeability based on porosity and the pore size distribution. The Sonic Scanner tool is an array sonic tool used to measure the compressional and shear sonic velocities in the formation. These measurements can then be used to calculate sonic porosity and Mechanical Rock Properties. The FMI is used to identify structure, depositional environment and fractures that may be present in the formations. The Mechanical Sidewall Coring Tool (MSCT) will take multiple rotary sidewall cores and return them to surface for analysis. The Modular formation Dynamics Tester (MDT) can take multiple pressures and fluid samples depending on its configuration. The Versatile Seismic Imager (VSIT) data aids in the tie between the seismic data and the log data.

General Interpretation of the data

The interpretation of the data is done using the ELAN-Plus computer program within GeoFrame. The Elemental Log ANalysis (ELAN) evaluation is done by optimizing simultaneous equations described by one or more interpretation models. The resulting analysis provides key petrophysical answers that describe the reservoir. Answers derived from this analysis include but are not limited to porosity, lithology, and permeability. Following is a brief description of the data provided on the ELAN analysis presentation.

Depth Track

GR – Gamma Ray

Caliper – Hole Size

RSOZ – Resistivity Standoff, Quality control indicating enlarged borehole.

DSOZ – Density Standoff, Quality control indicating enlarged borehole.

Bad Hole Flag - Quality control indicator, hole is too large or rugose for a measurement to be made.

Track 1

RLA5 to RLA2 – Array laterolog resistivity measurements with different depth of investigation. RLA5 is the deepest depth of investigation

RXO_HRLT – Laterolog resistivity measurement with shallow depth of investigation indicating the resistivity of the invaded zone.

Track 2

PEFZ – Photoelectric Effect. This is used for lithology identification.

RHOZ – Measurement of the bulk density of the formation. This is used in combination with the neutron and sonic for lithology identification as well as identification of fluids in the porosity.

Neutron - Measurement of the neutron porosity (lime) of the formation. This is used in combination with the density and sonic for lithology identification as well as identification of fluids in the porosity.

Density Correction – Correction applied to the density measurement for borehole affects such as mudcake.

DTCO – Delta T, sonic travel time of the compressional mode from the Sonic Scanner

Track 3

Kint ELAN – Permeability derived from the ELAN analysis. Core data presented if available.

Track 4

Porosity – Effective porosity as calculated by ELAN. This analysis also includes the vuggy porosity identified in the carbonates. Core data presented if available.

Track 5

Volumetric display of lithology and fluids solved for in ELAN. Core data presented if available.

Detailed Interpretation of the Injection Zone (Mount Simon)

The injection zone in the ADM CCS #1 well is the Mount Simon Formation which extends from the base of the Eau Claire Shale at 5544 ft to the top of the Granite Wash zone at 7049 ft. The petrophysical model used to evaluate the Mount Simon Formation included all minerals identified to be present in significant quantities in the cores that were analyzed for lithology. Though the Mount Simon is considered to be a clean sand, the major reservoir type rocks of limestone and dolomite were also included in the model. The clays used in the model were illite, chlorite, and kaolinite. Also included in the analysis is orthoclase due to the significant amount of potassium feldspar minerals found in the cores. Water was the only fluid included in the formation model, but the T2 pore size distribution measurement from the CMR tool was used to differentiate the free fluids from the bound fluids.

The results of the analysis indicate that the Mount Simon can be thought of as three separate units primarily based on the pore volume and pore size distribution. The bottom interval in the Mount Simon contains the highest average porosity and quite good permeability. This interval extends from the base up to 6420 ft. The section of the Mount Simon from 6420 ft to approximately 5950 ft is relatively low porosity with significantly reduced permeability. The third interval of the Mount Simon is from approximately 5950 ft to the top of the Mount Simon at 5544 ft. While the lithology does not vary significantly and is dominated by sand (quartz), there can be up to 15% clay and 25% orthoclase.

The bottom interval in the Mount Simon is the primary injection zone and has an average porosity of 16.8%, but there are intervals where the porosity approaches 30%. Average permeability in this interval is 33 md however permeability in the actual injection interval ranges from 60 md to several hundred md. There are a few thin shale intervals within the bottom section of the Mount Simon however, correlating this interval in the CCS #1 well with the Verification Well #1 it is thought that these shale intervals are

more likely to act as baffles rather than barriers to the movement of injected CO₂ as they do not appear to be continuous.

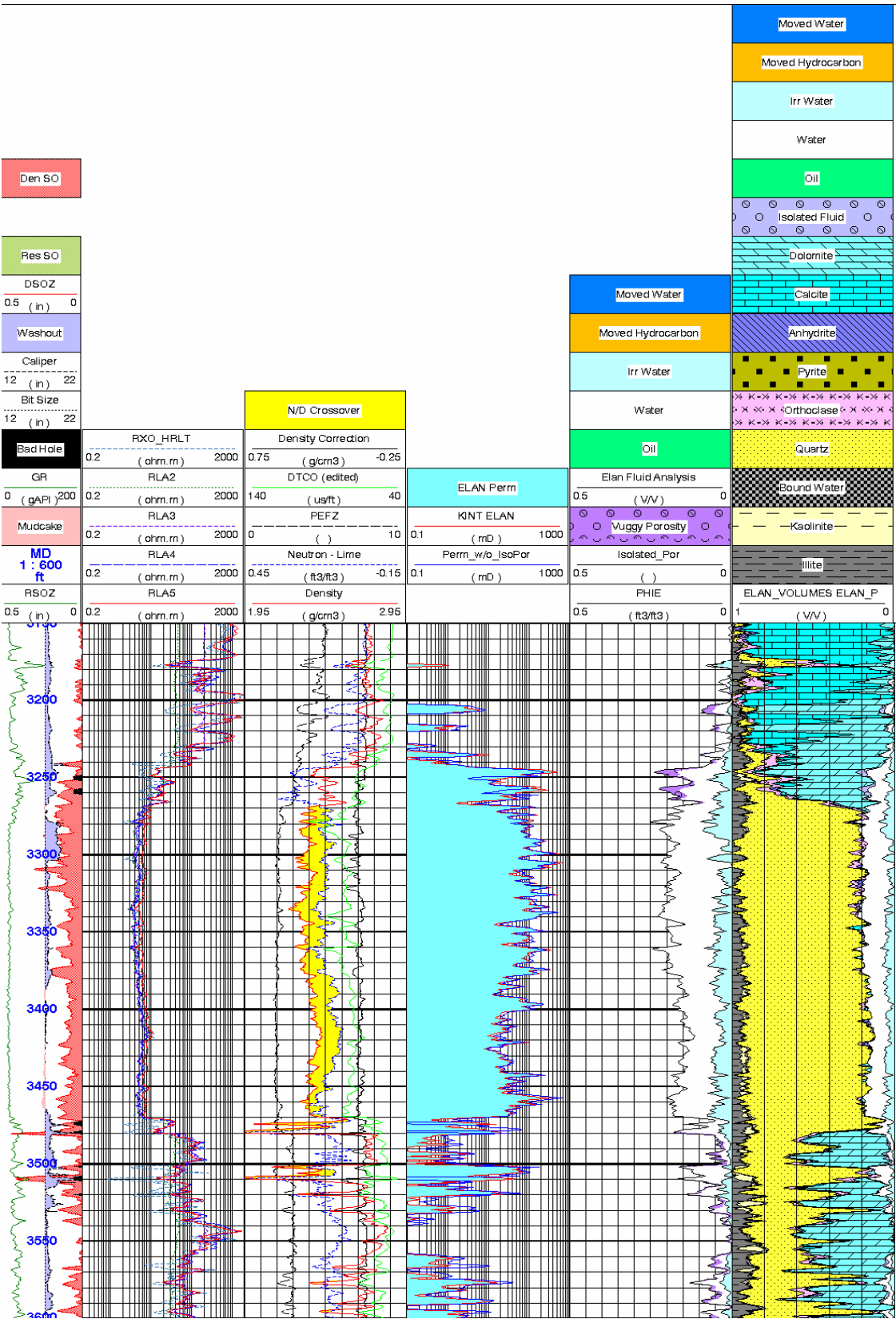
The middle interval of the Mount Simon has an average porosity of 9% and an average permeability of only 2.5 md. Based on the CMR pore size distribution and measurement of bound fluids, most of the fluids in this interval appear to be bound fluids, hence the greatly reduced permeability. While this interval is not considered to be a seal to the movement of CO₂, it will significantly retard the upward movement of CO₂.

The top interval of the Mount Simon has an average porosity of 10.6% and an average permeability of 66 md. The permeability increase in this interval is due to the measurement of the pore size distribution indicating that in this interval, while having lower total pore volume than the bottom interval the pores are larger therefore permeability is greater.

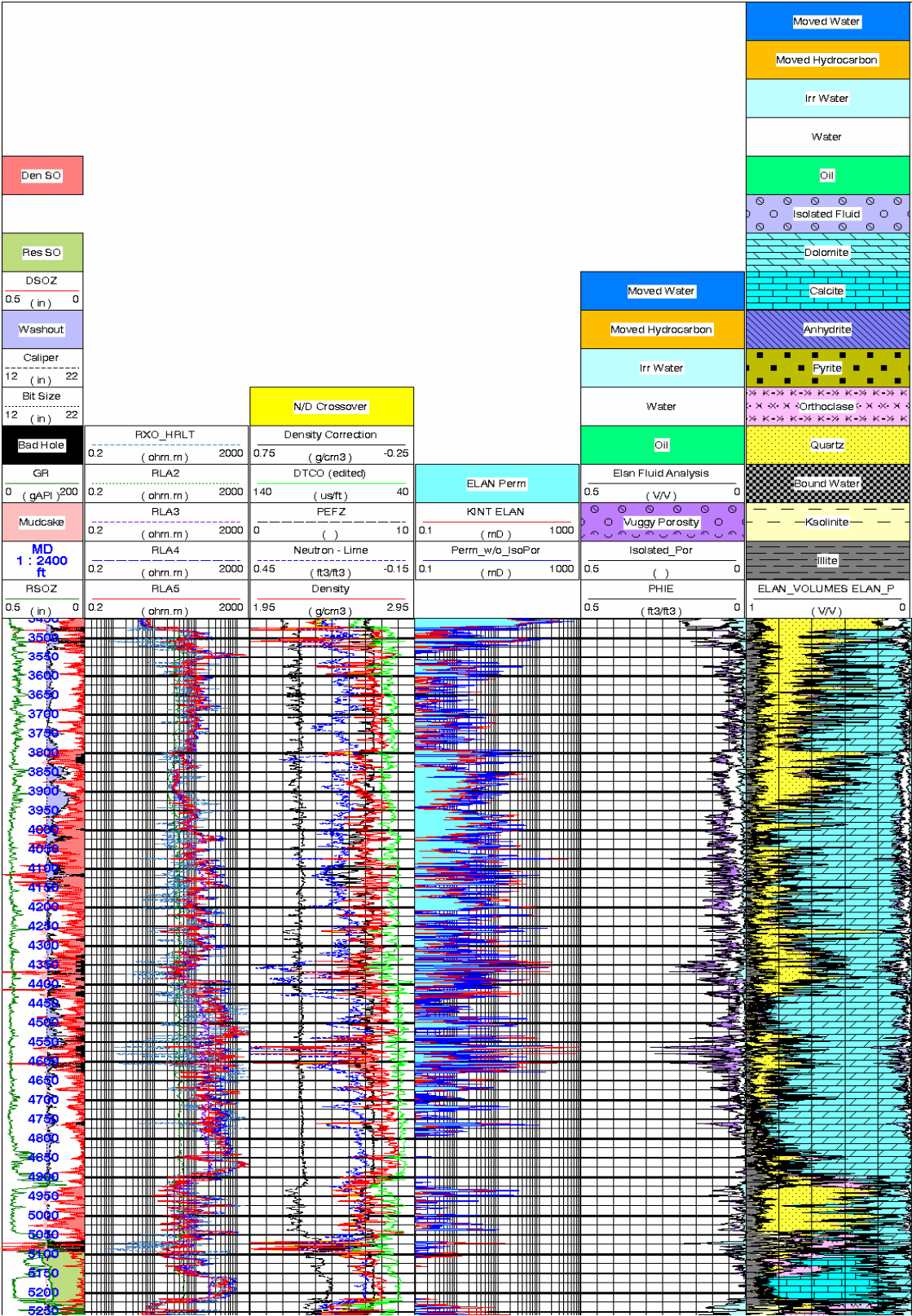
Detailed Interpretation of the Primary Seal (Eau Claire Shale)

The Eau Claire Shale will act as the primary seal for injected CO₂ into the Mount Simon. The Eau Claire Shale is 317 feet thick and covers the interval from 5227 ft to 5544 ft. The clays identified from the analysis include primarily illite and chlorite, with just a small amount of kaolinite. Based on the analysis of the CMR data the pore sizes in the Eau Claire are quite small and the resulting permeability is therefore very low. There are only a few small intervals of less than a few feet that have any permeability greater than 0.1 mD and these do not appear to be continuous. The Eau Claire Shale should provide a good seal for CO₂ injected into the Mount Simon.

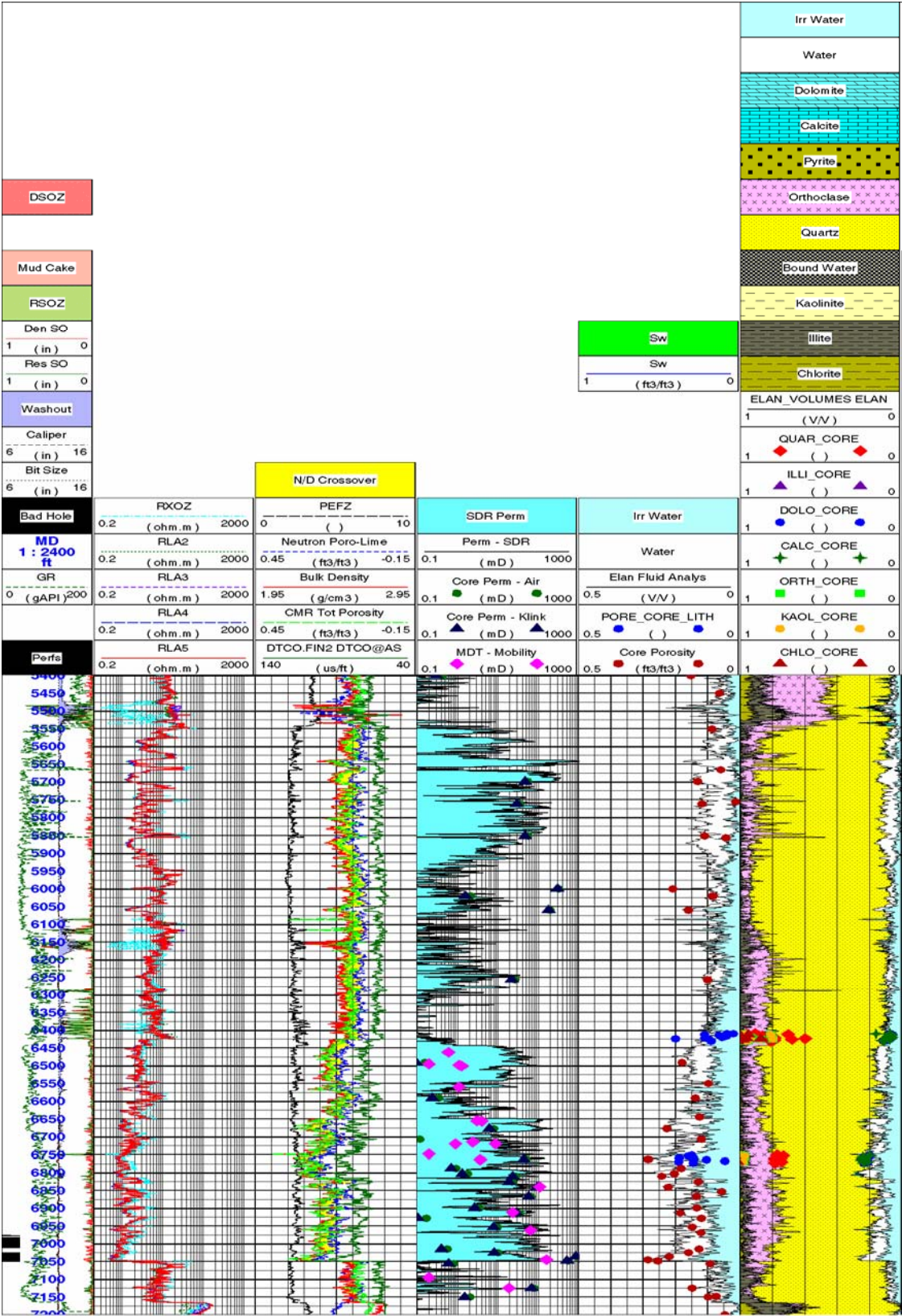
ELAN of St. Peter – CCS #1



ELAN of Knox – CCS #1



ELAN of Mt. Simon – CCS #1





Archer Daniels Midland Company
P.O. Box 1470, Decatur IL 62525

July 8, 2011

Mr. Steve Nightingale
Illinois Environmental Protection Agency
Bureau of Land, Permit Section #33
1021 N. Grand Ave. East
P.O. Box 19276
Springfield, IL 62794-9276

Via Certified Mail

Re: Permit No. UIC-012-ADM
CCS1 Well Completion Report Supplemental 2

Dear Mr. Nightingale:

ADM submitted the Well Completion Report for the CCS#1 injection well on May 5, 2010 and a supplemental dated May 16, 2011. This second supplemental includes the "as-built" information for the surface facilities and the Professional Engineer certification as requested by IEPA.

Included in this supplement is a revision of the surface facilities instrumentation summary table that has been revised to reflect the current instrumentation installed. Also, included are updated PFD and P&ID which reflect the as-built conditions. These were originally included as Appendix A & B respectively, in the June 3, 2010 Major Modification application.

Finally, a General Application for Permit (LPC-PA1) is included with this submittal. The engineering certification is referenced to the Certification of Well Completion Report statement which includes the Professional Engineers certification for the report.

With this supplement, ADM believes the completion report is complete. ADM requests the Agency complete its review of the well as soon as possible to ensure the project remains on

schedule for injection. If you have any questions regarding this please contact Sallie Greenberg at 217-244-4068 or myself at 217-451-6330.

Sincerely,

A handwritten signature in black ink, appearing to read "Dean Frommelt", with a stylized flourish at the end.

Dean Frommelt

Division Environmental Manager

Corn Processing & BioProducts

Cc: Kevin Lesko – IEPA
Mark Burau – ADM
Mike Marin – ADM
Rob Finley – ISGS
Sallie Greenberg – ISG



Illinois
Environmental
Protection Agency

Bureau of Land
1021 North Grand Avenue East
Box 19276
Springfield, IL 62794-9276

GENERAL APPLICATION FOR PERMIT (LPC-PA1)

This form must be used for any application for permit, except for landscape waste composting or hazardous waste management facilities regulated in accordance with RCRA, Subtitle C from the Bureau of Land. One original and two (2) photocopies, or three (3) if applicable, of all permit application forms must be submitted. Attach the original and appropriate number of copies of any necessary plans, specifications, reports, etc. to fully support and describe the activities or modifications being proposed. Attach sufficient information to demonstrate compliance with all applicable regulatory requirements. Incomplete applications will be rejected. Please refer to the instructions for further guidance.

Note: Permit applications which are hand-delivered to the Bureau of Land, Permit Section must be delivered to 1021 North Grand Avenue East between the hours of 8:30 a.m. to 5:00 p.m., Monday through Friday (excluding State holidays).

Please type or print legibly.

I. SITE IDENTIFICATION

Name: Archer Daniels Midland Company - Corn Processing Site # (Illinois EPA): 1150155136
Physical Site Location (street, road, etc.): 4666 Faries Parkway
City, Zip Code: Decatur, 62526 County: Macon
Existing DE/OP Permit Nos. (if applicable): N/A

II. OWNER/OPERATOR IDENTIFICATION

OWNER

OPERATOR

Name: Archer Daniels Midland Company - Corn Processing Same
Address: 4666 Faries Parkway
Decatur, IL 62526
Contact Name: Dean Frommelt
Phone #: (217) 451-6330 ()

III. PERMIT APPLICATION IDENTIFICATION

TYPE SUBMISSION/REVIEW PERIOD:

- ☐ New Landfill/180 days (35 IAC Part 813)
- ☐ Landfill Expansion/180 days (35 IAC Part 813)
- ☐ Sign. Mod to Operate/90 days (35 IAC Part 813)
- ☐ Other Sign. Mod/90 days (35 IAC Part 813)
- ☐ Renewal of Landfill 90 days (35 IAC Part 813)
- ☐ Developmental/90 days (35 IAC Part 807)
- ☐ Operating/45 days (35 IAC Part 807)
- ☐ Supplemental/90 days (35 IAC Part 807)
- ☐ Permit Transfer/90 days (35 IAC Part 807)
- ☐ Renewal of Experimental Permit (35 IAC Part 807)

TYPE FACILITY:

- ☐ Landfill
- ☐ Land Treatment
- ☐ Transfer Station
- ☐ Treatment
- ☐ Storage
- ☐ Incinerator
- ☐ Composting
- ☐ Recycling/Reclamation
- ☒ Other (Specify)
Carbon Sequestration

TYPE WASTE:

- ☐ General Municipal Refuse
- ☐ Hazardous
- ☐ Special (Non-hazardous)
- ☐ Chemical Only (exc. putrescible)
- ☐ Inert Only (exc. chemical and putrescible)
- ☐ Used Oil
- ☐ Potentially Infectious Medical Waste
- ☐ Landscape Waste
- ☒ Other (Specify)
Carbon Dioxide

DESCRIPTION OF THIS PERMIT REQUEST: (Include a brief narrative description here.)

UIC Class I Non-Hazardous Permit for a research project to demonstrate the potential of the Mt. Simon Sandstone, a major regional saline-water bearing reservoir in the Illinois Basin, to be a significant Carbon Dioxide geologic sequestration formation.

IL 532-1857
LPC 350 Rev. 2/03

This Agency is authorized to require this information under Illinois Revised Statutes, 1979, Chapter 111 1/2, Section 1039. Disclosure of this information is required under that Section. Failure to do so may prevent this form from being processed and could result in your application being denied. This form has been approved by the Forms Management Center.

IV. COMPLETENESS REQUIREMENTS

The following items must be checked Yes, No or N/A. Each item will be reviewed by the log clerk. Blank items will result in

rejection of the application. Please refer to the instructions for further guidance.

1. Have all required public notice letters been mailed in accordance with the LPC-PA16 instructions? (If so, provide a list of those recipients of the required public notice letters for Illinois EPA retention.) Such retention shall not imply any Illinois EPA review and/or confirmation of the list.) ☐ Yes ☐ No ☒ N/A
2. a. Is the Siting Certification Form (LPC-PA8) completed and enclosed? ☐ Yes ☐ No ☒ N/A
b. Is siting approval currently under litigation? ☐ Yes ☐ No ☒ N/A
3. a. Is a closure, and if necessary a post closure, plan covering these activities being submitted, or
b. has one already been approved? (Provide permit number _____.) ☐ Yes ☐ No ☒ N/A
4. a. For waste disposal sites only: Has any employee, owner, operator, officer or director of the owner or operator had a prior conduct certification denied, canceled or revoked? ☐ Yes ☒ No ☐ N/A
b. Have you included a demonstration of how you comply or intend to comply with 35 Ill. Adm. Code Part 745? ☐ Yes ☐ No ☒ N/A
5. a. Is land ownership held in beneficial trust? ☐ Yes ☒ No ☐ N/A
b. If yes, is a beneficial trust certification form (LPC-PA9) completed and enclosed? ☐ Yes ☐ No ☒ N/A
6. a. Does the application contain information or proposals regarding the hydrogeology; groundwater monitoring, modeling or classification; a groundwater impact assessment; or vadose zone monitoring for which you are requesting approval? ☐ Yes ☐ No ☒ N/A
b. If yes, have you submitted a third (3rd) copy of the application (4 total) and supporting documents?

V. SIGNATURES (Original signatures required. Signature stamps or applications transmitted electronically or by facsimile are not acceptable.)

All applications shall be signed by the person designated below as a duly authorized representative of the owner and/or operator.
Corporation - By a principal executive officer of at least the level of vice-president.
Partnership or Sole Proprietorship - By a general partner or the proprietor, respectively.
Government - By either a principal executive officer or a ranking elected official.

A person is a duly authorized representative of the owner and operator only if:

1. They meet the criteria above or the authorization has been granted in writing by a person described above; and
2. is submitted with this application (a copy of a previously submitted authorization can be used).

I hereby affirm that all information contained in this Application is true and accurate to the best of my knowledge and belief.

I do herein swear that I am a duly authorized representative of owner/operator and I am authorized to sign this permit application form.

Owner Signature: [Signature] Title: Decatur Corn Plant Manager Date: July 08, 2011
Owner FEIN or S.S. Number: 41-0129150

Operator Signature: _____ Title: Same as Owner Date: Same as Owner
Operator FEIN or S.S. Number: Same as Owner

Notary: Subscribe and sworn before me this 8 day of July, 2011.
Notary Signature: [Signature] Notary Seal: _____
My commission expires on: 5/22/2014



Engineer Signature: [Signature] Title: Project Manager Date: 7-8-11
Engineer Address: ADM Design Services
1900 E. Eldorado St.
Decatur, IL 62521
Engineer Seal: See attached certification statement.

Engineer Phone No. (217) 451-3622

All information submitted as part of the Application is available to the public except when specifically designated by the Applicant to be treated confidentially as a trade secret or secret process in accordance with Section 7(a) of the Environmental Protection Act, applicable Rules and Regulations of the Illinois Pollution Control Board and applicable Illinois EPA rules and guidelines.

Certification of Well Completion Report

To the best of my knowledge and belief, I affirm that the Well Completion Report submitted May 5, 2010 and supplemental information dated May 16, 2011 and July 8, 2011 under Permit # UIC-012-ADM, for the Carbon Capture & Sequestration (CCS) Well #1 Project by the Archer Daniels Midland Company in Decatur, Illinois, is based on true and accurate information as developed by the professionals listed below:



PE Stamp

A handwritten signature of Michael J. Marin in black ink.

Michael J. Marin, P.E., S.E.

7-8-11

(date)

My license renewal date is November 30, 2011.

CCS Well #1 Project – List of Professionals:

-
- (1) Well Design and Construction: Robert C. Herr III, P.E. (Illinois #062-039059); Consulting Engineer
 - (2) Subsurface Geology & Hydrogeology: Dr. Robert J. Finley, L.P.G. (Licensed Professional Geologist in Texas; #5003); University of Illinois and Dr. Hannes E. Leetaru, L.P.G. (Licensed Professional Geologist in Illinois; #196-000690); University of Illinois
 - (3) Design of Building Foundations, Masonry Electrical Building, Utility Bridges & Pipe Supports: Michael J. Marin, P.E., S.E. (Illinois); Civil/Structural Engineer; ADM Design Services - a division of Archer Daniels Midland Company
 - (4) Design of Pre-Engineered Building Steel: Bejun N. Anklesaria, S.E. (Illinois #081-005323); Mesco Building Solutions
 - (5) CO₂ Transmission Piping Design, Utility Piping Design & Compressor Interstage Piping Isometrics: ADM Design Services - exempt from licensure requirement per industrial exemption for employees of a private company practicing engineering for systems to be used internally by that company (Illinois Professional Engineering Practice Act of 1989: 225 ILCS 325 Section 3.e.4.)
 - (6) Process design; equipment process specifications; vent header process design; relief valve process specifications for pump & pipeline systems; process hazard reviews & process-related Schlumberger risk reduction action items for surface equipment (not including injection well & reservoir); process flow diagrams; P&ID review & comments; operating procedures: Kevin Fisher, P.E. (Texas # 72041 & Illinois #062-062954); Trimeric Corporation

Surface Facilities Instrumentation Summary

Description/Location	ADM Tag	Measurement	Brand	Model	Service	Operating Range	Operating Range Units	P&ID
Oxygen Analyzer downstream of Blower	ARX-001	Oxygen	Advanced Instrument, Inc	GPR-1600	Wet CO ₂	Auto-range	ppm or %	23443-101 SHT 2 OF 2
Moisture Analyzer downstream of Dehydration Unit	ARX-006	Moisture	AMETEK	5100-NCM	Dry CO ₂	0 - 630	ppmv	23433-111 SHT 4 OF 11
Compressor Discharge Flow	FIT-005	Flow	SCADASense	4203	Dry CO ₂	23,000 - 101,100	lb/hr	23433-111 SHT 8 OF 11
Injection flow rate	FIT-006	Flow	SCADASense	4203	Dry CO ₂	23,000 - 101,000	lb/hr	23433-111 SHT 9 OF 11
Differential pressure of CO ₂ across the inlet separator & Contactor	PDIT-401	Differential Pressure	ABB	264DSHSSA2A1 L1N2	Wet/Dry CO ₂	0 - 5	psi	23433-111 SHT 5 OF 11
HE-204 A/B outlet pressure	PIT-006	Pressure	ABB	264HSVKTA1L1 N2	Dry CO ₂	0 - 1400	psig	23433-111 SHT 9 OF 11
Pipeline inlet Pressure upstream of valve V-347	PIT-007	Pressure	ABB	264HSVKTA1L1 N2	Dry CO ₂	0 - 2000	psig	23433-111 SHT 9 OF 11
Pipeline inlet pressure downstream of valve V-347	PIT-008	Pressure	ABB	264HSVKTA1L1 N2	Dry CO ₂	0 - 2000	psig	23433-111 SHT 9 OF 11
Pipeline outlet pressure (Wellhead Pressure)	PIT-009	Pressure	ABB	264HSVKTA1L1 N2	Dry CO ₂	0 - 2000	psig	23433-111 SHT 9 OF 11
Multistage Pump discharge pressure	PIT-010	Pressure	ABB	264HSVKTA1L1 N2	Dry CO ₂	1400 - 2000	psig	23433-111 SHT 9 OF 11
Multistage Pump suction pressure	PIT-011	Pressure	ABB	264HSVKTA1L1 N2	Dry CO ₂	0 - 1400	psig	23433-111 SHT 9 OF 11

Description/Location	ADM Tag	Measurement	Brand	Model	Service	Operating Range	Operating Range Units	P&ID
Pipeline pressure upstream of Wellhead Tree	PIT-013	Pressure	ABB	264HSVKTA1L1 N2	Dry CO2	0 - 2000	psig	23433-111 SHT 9 OF 11
Well Annulus pressure	PIT-014	Pressure	ABB	264HSVKTA1L1 N2	Dry CO2	0 - 150	psig	23433-111 SHT 9 OF 11
Shell-side inlet pressure of HE-402	PIT-4402A	Pressure	ABB	264HSVKTA1L1 N2	TEG	0 - 100	psig	23433-111 SHT 6 OF 11
Shell-side outlet pressure of HE-402	PIT-4402B	Pressure	ABB	264HSVKTA1L1 N2	TEG	0 - 100	psig	23433-111 SHT 6 OF 11
Shell-side inlet pressure of HE-403	PIT-4403A	Pressure	ABB	264HSVKTA1L1 N2	TEG	0 - 105	psig	23433-111 SHT 6 OF 11
Shell-side outlet pressure of HE-403	PIT-4403B	Pressure	ABB	264HSVKTA1L1 N2	TEG	0 - 105	psig	23433-111 SHT 6 OF 11
HE-204 A/B inlet pressure	PIT-005	Pressure	ABB	264HSVKTA1L1 N2	Dry CO ₂	0 - 1400	psig	23433-111 SHT 8 OF 11
Blower suction pressure	PTX-101A	Pressure	Rosemount	3051CG	Wet CO ₂	0 - 1	psia	23443-101 SHT 1 OF 2
Blower discharge pressure	PTX-101B	Pressure	Rosemount	3051CG	Wet CO ₂	0 - 18	psig	23443-101 SHT 1 OF 2
Blower Aftercooler Separator outlet pressure	PTX-102	Pressure	Rosemount	3051CG	Wet CO ₂	0 - 18	psig	23443-101 SHT 2 OF 2
VS-201 1st Stage suction scrubber pressure	PTX-201A	Pressure	Rosemount	3051CG	Wet CO ₂	0 - 25	psig	23433-111 SHT 1 OF 11
VS-201 1st Stage discharge pressure	PTX-201B	Pressure	Rosemount	3051CG	Wet CO ₂	0 - 75	psig	23433-111 SHT 1 OF 11
VS-201 2nd Stage suction scrubber pressure	PTX-202A	Pressure	Rosemount	3051CG	Wet CO ₂	0 - 75	psig	23433-111 SHT 2 OF 11
VS-201 2nd Stage discharge pressure	PTX-202B	Pressure	Rosemount	3051CG	Wet CO ₂	0 - 250	psig	23433-111 SHT 2 OF 11

Description/Location	ADM Tag	Measurement	Brand	Model	Service	Operating Range	Operating Range Units	P&ID
VS-201 3rd Stage suction scrubber pressure	PTX-203A	Pressure	Rosemount	3051CG	Wet CO ₂	0 - 250	psig	23433-111 SHT 3 OF 11
VS-201 3rd Stage discharge pressure	PTX-203B	Pressure	Rosemount	3051CG	Wet CO ₂	0 - 650	psig	23433-111 SHT 3 OF 11
VS-201 4th Stage suction scrubber pressure	PTX-204A	Pressure	Rosemount	3051CG	Dry CO ₂	0 -650	psig	23433-111 SHT 7 OF 11
VS-201 4th Stage discharge pressure	PTX-204B	Pressure	Rosemount	3051CG	Dry CO ₂	0 - 1400	psig	23433-111 SHT 7 OF 11
VS-301 1st Stage suction scrubber pressure	PTX-301A	Pressure	Rosemount	3051CG	Wet CO ₂	0 - 25	psig	23434-111 SHT 1 OF 4
VS-301 1st Stage discharge pressure	PTX-301B	Pressure	Rosemount	3051CG	Wet CO ₂	0 - 75	psig	23434-111 SHT 1 OF 4
VS-301 2nd Stage suction scrubber pressure	PTX-302A	Pressure	Rosemount	3051CG	Wet CO ₂	0 - 75	psig	23434-111 SHT 2 OF 4
VS-301 2nd Stage discharge pressure	PTX-302B	Pressure	Rosemount	3051CG	Wet CO ₂	0 - 250	psig	23434-111 SHT 2 OF 4
VS-301 3rd Stage suction scrubber pressure	PTX-303A	Pressure	Rosemount	3051CG	Wet CO ₂	0 - 250	psig	23434-111 SHT 3 OF 4
VS-301 3rd Stage discharge pressure	PTX-303B	Pressure	Rosemount	3051CG	Wet CO ₂	0 -650	psig	23434-111 SHT 3 OF 4
VS-301 4th Stage suction scrubber pressure	PTX-304A	Pressure	Rosemount	3051CG	Dry CO ₂	0 -650	psig	23434-111 SHT 4 OF 4
VS-301 4th Stage discharge pressure	PTX-304B	Pressure	Rosemount	3051CG	Dry CO ₂	0 - 1400	psig	23434-111 SHT 4 OF 4
Temperature of CO ₂ exiting the contactor	TI-401A	Temperature	Pyromation	006SC-6HN-22(6)	Dry CO ₂	95 - 100	°F	23433-111 SHT 5 OF 11

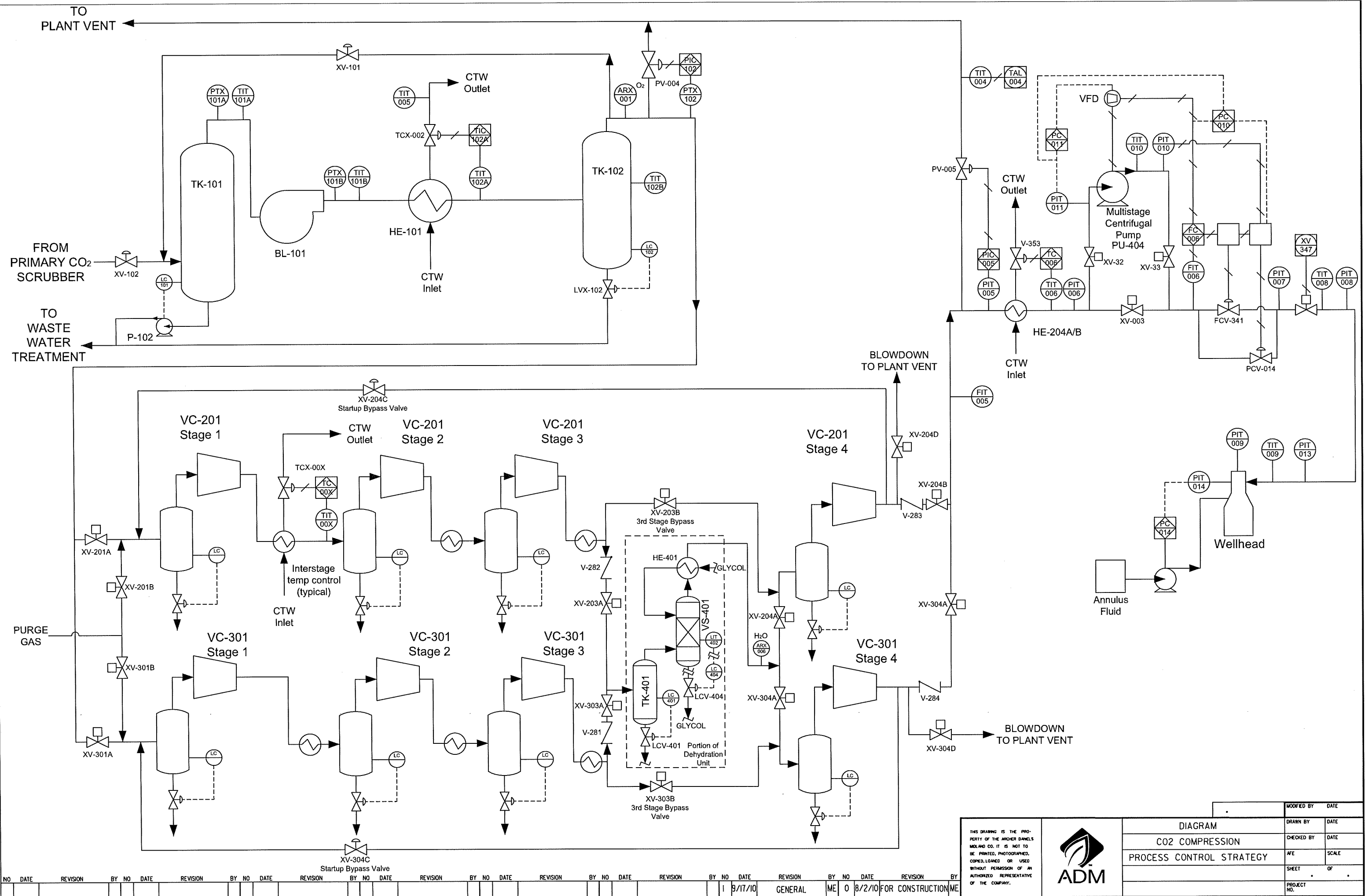
Description/Location	ADM Tag	Measurement	Brand	Model	Service	Operating Range	Operating Range Units	P&ID
Temperature of TEG exiting the bottom of the contactor	TI-401C	Temperature	Pyromation	R1T185L483-002(11/16/SC-6HN-22(6)	TEG	95 - 100	°F	23433-111 SHT 5 OF 11
Bulk temperature of TEG in the glycol flash separator	TI-402	Temperature	Pyromation	R1T185L483-006SC-6HN-22(6)	TEG	95 - 120	°F	23433-111 SHT 5 OF 11
PV-005 outlet temperature (CO ₂ Vent)	TIT-004	Temperature	Pyromation	Note 1	Dry CO ₂	0 - 250	°F	23433-111 SHT 8 OF 11
HE-204A/B CO ₂ outlet temperature	TIT-006	Temperature	Pyromation	R1T185L483-002(11/16)SC-6HN-22(6)	Dry CO ₂	95 -105	°F	23433-111 SHT 9 OF 11
Pipeline inlet CO ₂ temperature	TIT-008	Temperature	Pyromation	R1T185L483-002(11/16)SC-6HN-22(6)	Dry CO ₂	95 - 115	°F	23433-111 SHT 9 OF 11
Pipeline outlet CO ₂ temperature	TIT-009	Temperature	Pyromation	R1T185L483-002(11/16)SC-6HN-22(6)	Dry CO ₂	95 - 115	°F	23433-111 SHT 9 OF 11
Multistage Pump discharge temperature	TIT-010	Temperature	Pyromation	Note 1	Dry CO ₂	95 - 115	°F	23433-111 SHT 9 OF 11
Blower inlet separator temperature	TIT-101A	Temperature	Rosemount	3144	Wet CO ₂	40 -100	°F	23443-101 SHT 1 OF 2
Blower discharge temperature	TIT-101B	Temperature	Rosemount	3144	Wet CO ₂	175 - 230	°F	23443-101 SHT 1 OF 2
HE-101 CO ₂ outlet temperature	TIT-102A	Temperature	Rosemount	3144	Wet CO ₂	90 - 100	°F	23443-101 SHT 2 OF 2
Blower Aftercooler Outlet Separator temperature	TIT-102B	Temperature	Rosemount	3144	Wet CO ₂	90 - 100	°F	23443-101 SHT 2 OF 2

Description/Location	ADM Tag	Measurement	Brand	Model	Service	Operating Range	Operating Range Units	P&ID
VS-201 1st Stage suction scrubber temperature	TIT-201A	Temperature	Rosemount	3144	Wet CO ₂	90 - 100	°F	23433-111 SHT 1 OF 11
VS-201 1st Stage Cylinder 1 temperature	TIT-201B	Temperature	Rosemount	3144	Wet CO ₂	250- 295	°F	23433-111 SHT 1 OF 11
VS-201 1st Stage Cylinder 3 temperature	TIT-201C	Temperature	Rosemount	3144	Wet CO ₂	250 - 295	°F	23433-111 SHT 1 OF 11
VS-201 2nd Stage suction scrubber temperature	TIT-202A	Temperature	Rosemount	3144	Wet CO ₂	90 - 100	°F	23433-111 SHT 2 OF 11
VS-201 2nd Stage Cylinder 2 temperature	TIT-202B	Temperature	Rosemount	3144	Wet CO ₂	270 - 315	°F	23433-111 SHT 2 OF 11
VS-201 2nd Stage Cylinder 4 temperature	TIT-202C	Temperature	Rosemount	3144	Wet CO ₂	270 - 315	°F	23433-111 SHT 2 OF 11
VS-201 3rd Stage suction scrubber temperature	TIT-203A	Temperature	Rosemount	3144	Wet CO ₂	90 - 100	°F	23433-111 SHT 3 OF 11
VS-201 3rd Stage Cylinder 6 temperature	TIT-203B	Temperature	Rosemount	3144	Wet CO ₂	220 - 260	°F	23433-111 SHT 3 OF 11
VS-201 4th Stage suction scrubber temperature	TIT-204A	Temperature	Rosemount	3144	Dry CO ₂	90 -100	°F	23433-111 SHT 7 OF 11
VS-201 4th Stage Cylinder 5 temperature	TIT-204B	Temperature	Rosemount	3144	Dry CO ₂	220 -265	°F	23433-111 SHT 7 OF 11
HE-201 outlet temperature	TIT-207A	Temperature	Rosemount	3144	Wet CO ₂	90 - 100	°F	23433-111 SHT 1 OF 11
HE-203 outlet temperature	TIT-207C	Temperature	Rosemount	3144	Wet CO ₂	90 - 100	°F	23433-111 SHT 3 OF 11
VS-301 1st Stage suction scrubber temperature	TIT-301A	Temperature	Rosemount	3144	Wet CO ₂	90 - 100	°F	23434-111 SHT 1 OF 4
VS-301 1st Stage Cylinder 1 temperature	TIT-301B	Temperature	Rosemount	3144	Wet CO ₂	250 - 295	°F	23434-111 SHT 1 OF 4

Description/Location	ADM Tag	Measurement	Brand	Model	Service	Operating Range	Operating Range Units	P&ID
VS-301 1st Stage Cylinder 3 temperature	TIT-301C	Temperature	Rosemount	3144	Wet CO ₂	250 - 295	°F	23434-111 SHT 1 OF 4
VS-301 2nd Stage suction scrubber temperature	TIT-302A	Temperature	Rosemount	3144	Wet CO ₂	90 - 100	°F	23434-111 SHT 2 OF 4
VS-301 2nd Stage Cylinder 2 temperature	TIT-302B	Temperature	Rosemount	3144	Wet CO ₂	270 - 315	°F	23434-111 SHT 2 OF 4
VS-301 2nd Stage Cylinder 4 temperature	TIT-302C	Temperature	Rosemount	3144	Wet CO ₂	270 - 315	°F	23434-111 SHT 2 OF 4
VS-301 3rd Stage suction scrubber temperature	TIT-303A	Temperature	Rosemount	3144	Wet CO ₂	90 - 100	°F	23434-111 SHT 3 OF 4
VS-301 3rd Stage Cylinder 6 temperature	TIT-303B	Temperature	Rosemount	3144	Wet CO ₂	220 - 260	°F	23434-111 SHT 3 OF 4
VS-301 4th Stage suction scrubber temperature	TIT-304A	Temperature	Rosemount	3144	Dry CO ₂	90 - 100	°F	23434-111 SHT 4 OF 4
VS-301 4th Stage Cylinder 5 temperature	TIT-304B	Temperature	Rosemount	3144	Dry CO ₂	220 - 265	°F	23434-111 SHT 4 OF 4
HE-301 outlet temperature	TIT-307A	Temperature	Rosemount	3144	Wet CO ₂	90 - 100	°F	23434-111 SHT 1 OF 4
HE-302 outlet temperature	TIT-307B	Temperature	Rosemount	3144	Wet CO ₂	90 - 100	°F	23434-111 SHT 2 OF 4
HE-303 outlet temperature	TIT-307C	Temperature	Rosemount	3144	Wet CO ₂	90 - 100	°F	23434-111 SHT 3 OF 4
Temperature of TEG at the outlet of the coil in the still column	TIT-4002A	Temperature	Pyromation	R1T185L483-002(11/16/SC-6HN-22(6)	TEG	100 - 150	°F	23433-111 SHT 6 OF 11

Description/Location	ADM Tag	Measurement	Brand	Model	Service	Operating Range	Operating Range Units	P&ID
Temperature of CO ₂ exiting the gas/glycol exchanger HE-401	TIT-401B	Temperature	Pyromation	R1T185L483-006SC-6HN-22(6)	Dry CO ₂	90 - 100	°F	23433-111 SHT 5 OF 11
HE-202 outlet temperature	TIT-207B	Temperature	Rosemount	3144	Wet CO ₂	90 - 100	°F	23433-111 SHT 2 OF 11
Shell-side inlet temperature of HE-402	TIT-4402A	Temperature	Pyromation	R1T185L483-002(11/16)SC-6HN-22(6)	TEG	255 - 275	°F	23433-111 SHT 6 OF 11
Shell-side outlet temperature of HE-402	TIT-4402B	Temperature	Pyromation	R1T185L483-002(11/16)SC-6HN-22(6)	TEG	300 - 320	°F	23433-111 SHT 6 OF 11
Tube-side outlet temperature of HE402	TIT-4402C	Temperature	Pyromation	R1T185L483-002(11/16)SC-6HN-22(6)	TEG	95 - 115	°F	23433-111 SHT 6 OF 11
Tube-side outlet temperature of HE-403	TIT-4402D	Temperature	Pyromation	R1T185H483-002(11/16)SC-6HN-22(6)	TEG	300 - 320	°F	23433-111 SHT 6 OF 11
Shell-side inlet temperature of HE-403	TIT-4403A	Temperature	Pyromation	R1T185H483-002(11/16)SC-6HN-22(6)	TEG	195 - 215	°F	23433-111 SHT 6 OF 11
Shell-side outlet temperature of HE-403	TIT-4403B	Temperature	Pyromation	R1T185H483-002(11/16)SC-6HN-22(6)	TEG	310 - 330	°F	23433-111 SHT 6 OF 11
Temperature of CO ₂ to the dehydration unit inlet separator	TT-401	Temperature	Pyromation	R1T185L483-006SC-6HN-22(6)	Wet CO ₂	90 - 100	°F	23433-111 SHT 5 OF 11

Note 1: Equipment is not ordered yet



PU-404
MULTISTAGE CENTRIFUGAL PUMP
 Manufacturer **WOOD GROUP**
 SJ0270 (TJ9000)/26
 200 HP, 460/60 HZ/3 PH
 Max Discharge Pressure 2200 psig
 274.5 US GPM @ 3,570 RPM
 Material 316 SS WETTED

NOTES

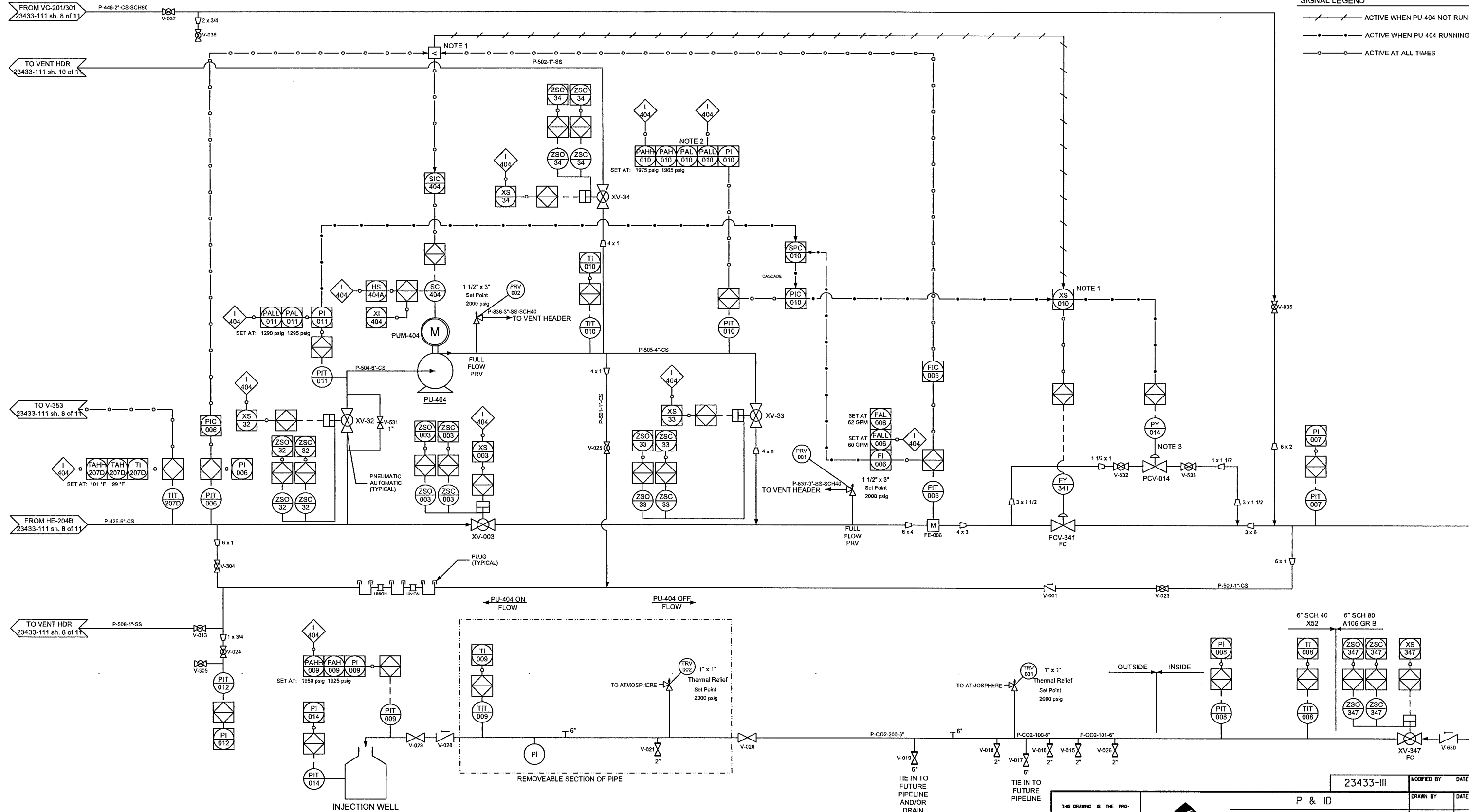
1. When PU-404 is running, PC-010 controls the position of PCV-014 and FCV-341 and PC-006/FC-006 low-select controls SIC-404. When PU-404 is not running, PC-006/FC-006 low-select controls the position FCV-341 and PC-010 is inactive and PCV-014 is closed.
2. PAL-010 and PALL-010 calculated per formula in I-404 interlock matrix.
3. PCV-014 has a minimum stop at 30% when PU-404 is confirmed running.

SIGNAL LEGEND

— / — / — ACTIVE WHEN PU-404 NOT RUNNING

— ● — ● — ACTIVE WHEN PU-404 RUNNING

— ○ — ○ — ACTIVE AT ALL TIMES

[illegible]

THIS DRAWING IS THE PROPERTY OF THE ARCHER DANIEL MIDLAND CO. IT IS NOT TO BE PRINTED, PHOTOGRAPHED, COPIED, LOANED OR USED WITHOUT PERMISSION OF AN AUTHORIZED REPRESENTATIVE OF THE COMPANY.



		23433-III	MODIFIED BY	DATE
P & ID COMPRESSION SYSTEM INJECTION PUMP			DRAWN BY	DATE
			CHECKED BY	DATE
			A/E	SCALE
			SHEET	9 OF 11
			PROJECT NO.	